STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 97-116

March 24, 1998

BANGOR HYDRO-ELECTRIC COMPANY
Proposed Increase in Rates

CORRECTED ORDER

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I. SUMMARY

We grant Bangor Hydro-Electric Company (Bangor Hydro, BHE or the Company) a rate increase of $13,222,365, or 9.86% over test year revenue, and $8,123,804, or 6.06% more than the § 312 rates currently in place. Our test year analysis produces a $10,713,505 revenue deficiency, based upon a 9.65% of cost of capital and 12.75% cost of equity. After inclusion of revenue delta adjustment of 15%, a $2,508,860 attrition allowance is added to the test year deficiency. We allocate the entire rate increase to core customers and reject the Commission Advocacy Staff's (Staff) proposed rate design because of the financial condition of the Company. We adopt a price cap plan, based upon an inflation index minus a productively factor of 1.2%. The plan includes a reconciliation mechanism for costs related to Maine Yankee.

II. INTRODUCTION

On May 8, 1997, BHE filed for a rate increase by filing new rates for effect on June 9, 1997. BHE sought an increase of $5 million, expected to be suspended until February, 1998 and an additional $4.5 million effective on January 1, 1999. BHE proposed the adoption of a Maine Yankee adjustment clause to provide for the reconciliation of all prudent Maine Yankee-related costs.

When Bangor Hydro filed its “permanent” rate increase request on May 8, it already had a request for a temporary rate increase of $10 million pending before the Commission. The temporary rates were necessary, BHE alleged, because the precarious financial condition of the Company would otherwise cause injury to the Company and its ratepayers.

We found that the temporary rates were necessary to prevent injury to the public interest. BHE’s financial condition was sufficiently precarious that ratepayers would likely pay higher costs in the future without the temporary rates. The Commission granted a temporary rate increase of $5.098 million effective July 1, 1997. *Bangor Hydro-Electric Company*, Docket No. 97-201, Order Part I on June 25, 1997 and Order Part II on August 13, 1997. At the same time, we ordered BHE to increase the amortization of its regulatory asset associated with the buyout of the Beaverwood Qualifying Facility contract by an annual rate of $5 million. The temporary rate increase was allocated to all rate classes of customers that do not have special rate contracts or special rate discounts associated with BHE’s space heating programs.

The temporary rate increase was offset by the increased amortization of the Beaverwood asset because the need for temporary rates was driven by the Maine Yankee Atomic Power Plant outage and the Commission had ordered a management audit into the prudence of the outage. The increased Beaverwood amortization prevented the inclusion of any Maine Yankee costs, including any replacement power costs, in the temporary rates. If Maine Yankee shutdown costs had been included in rates, retroactive ratemaking would prevent the recovery of any costs later found to be imprudent.

On July 16, 1997, the Company modified its request in this case to a single increase of $20.6 million effective at the conclusion of the 8-month suspension period, again applying the increase only to “core” customers. In its rebuttal testimony, the Company revised its request to $22.11 million.

At the conclusion of hearings, BHE asked for a temporary increase pursuant to 35 M.R.S.A. § 312 of $8.3 million. Although we essentially agreed with Bangor Hydro that $8.3 million was the undisputed amount within section 312, we declined to change rates again in December after a rate change already had occurred in July and one was anticipated for February 1998. Accordingly, we converted the §1322 temporary rates into §312 temporary rates subject to refund. As section 312 permits rates subject to refunds, we returned the Beaverwood amortization to the pre-July 1, 1997 level. BHE’s §312 Motion therefore produced increased earnings but no increase in rates.

A review of the recent regulatory history involving Bangor Hydro is necessary to understand all the issues presented in this rate case. In February 1995, we allowed Bangor Hydro substantial pricing flexibility. *Bangor Hydro-Electric Company*, Docket No. 94-125 (Phase I), 159 P.U.R. 4th 460 (Me. P.U.C. February 14, 1995). This pricing program, referred to as the Alternative Marketing Plan or AMP, allowed the Company to exercise greater discretion in its pricing decisions. As part of the pricing flexibility program, and pursuant to our authority in 35-A. M.R.S.A. §3195(6), we waived BHE’s fuel cost adjustment. We did not, in *Phase I*, implement a rate cap for BHE, and instead instituted the flexible pricing plan while continuing the AMP investigation in Phase II to consider whether a more formal risk sharing mechanism should be adopted.

Since the *AMP Phase I* Order, BHE entered into approximately 20 special contracts pursuant to its flexible pricing program. BHE also has adopted two discounted space heating rate schedules pursuant to the same authority.

After considering proposals submitted by the Advocacy Staff and the OPA in *Phase II*, we adopted BHE’s position and declined to adopt a formal price cap plan. *Bangor Hydro-Electric Company,* Docket No. 94-125 (Phase II) (Me. P.U.C., July 10, 1996). In reaching this conclusion, we relied in part on BHE's public commitment to avoid general rate increases for 5 years:

> In our Phase I Order, we listed several potential benefits of a rate cap mechanism. We find those benefits can be achieved for BHE and its ratepayers without imposing a formal plan at this time. So long as BHE keeps its promise to customers, improvement in the Company’s financial condition will only be achieved by BHE’s ability to operate more efficiently or to offer additional services to customers. Regulatory efficiency will be improved because neither an annual performance review nor any expedited rate relief proceedings will take place, thus allowing all parties to husband their increasingly scarce resources.
>
> By adopting this approach, we do not intend to relax any of our regulatory responsibilities.... Should the Company file a rate case, that filing will be subject to the full scrutiny of the Commission and of any intervenors who wish to participate. Of course, the Company will have the full responsibility to explain why it could not keep its stayout promise.

AMP Phase II Order at 5.

Bangor Hydro blames the failure of the informal stayout on the dire financial condition of the Company. The financial condition has become unbearable without higher rates largely because of events at the Maine Yankee Atomic Power Plant. Maine Yankee was off-line for most of 1995 due to resleeving of steam generation tubes. Significant expenses were incurred because of the repair and the need to purchase replacement power during the shutdown. In late 1996, Maine Yankee again went off-line, for a period originally thought to be for up to a few months, but that eventually led to the permanent shutdown of the plant. The 1997 shutdown again led to significant repair costs before the permanent shutdown as well as significant replacement power costs. From January 1995 through April 1997, the Company estimated that repairs and replacement power have cost BHE an unanticipated $20-25 Million.

The extended shutdowns of the Maine Yankee plant, coupled with Bangor Hydro's request for a rate increase, led the Commission in May, 1997 to order a management audit to determine "whether Maine Yankee was operated prudently from January 1, 1994 to [June 1997] and what costs, if any, were associated with any imprudency." On September 4, 1997, the management auditors filed their report in this case. The auditors concluded that Maine Yankee management had acted imprudently during the audit period and as a result incurred $95.9 million of excessive costs.

The shutdown of Maine Yankee occurred shortly before the Audit Report was issued. The Company moved in limine to remove the audit and Maine Yankee prudence issues from this case and into a separate investigation, because the historical costs identified by the auditors as imprudent were irrelevant to this proceeding given the shutdown of the plant. The Commission granted BHE's Motion, because the shutdown did render the audit report only marginally relevant to the rate case and because shutdown prudence questions could not be investigated adequately before the statutory deadline of this case. The Commission initiated a §1303 investigation into the prudence of the Maine Yankee shutdown and the operation of the plant leading up to the shutdown, and deferred the Maine Yankee prudence issues from this case into the separate investigation. The Commission also ordered a continuation of the management audit to consider whether Maine Yankee management and owners acted prudently to shut down the plant, and even if the shutdown was economic, whether Maine Yankee imprudently operated the plant, causing the premature shutdown of the plant. Thus, while events at Maine Yankee may have caused this request for a rate increase, the investigation of the prudence of the shutdown of Maine Yankee and the ratemaking remedies due to any imprudence must await another case. We will discuss the consequences of this delay in Section VII.

Events other than Maine Yankee added to BHE's financial distress: rate discounts necessary to keep customers, such as Lincoln Pulp and Paper, one of the largest customers, connected to the grid, and the high level of Company debt that resulted from financing the buyouts of the UltraPower QF contracts. In its brief, the Company characterizes the developments, including the Maine Yankee problems, that led to the request to increase rates as "beyond the Company's control."

While we are not convinced that some or even most of all of the factors that led to this rate case were beyond BHE's control, we have not considered the fact that BHE was unable to "stay out" in deciding the amount of rate increase that produces just and reasonable rates. We accepted the risk that the stayout was unenforceable. By our analysis of the issues in this case and the management audits and future prudence investigations of Maine Yankee, however, we will live up to our promise to thoroughly scrutinize the merits of BHE's rate increase request.

We do consider the failure of the informal stayout in deciding whether to adopt a formal rate plan at this time. We discuss the rate cap issue in Section VII, but it is worth noting the difference in approach taken by the Company in this case compared to the AMP . In *AMP Phase II*, we stated that "[t]he Company has recognized that increasing its rates would put it at a very unfavorable position given that, through any of several means, competition will be increasing in the electric industry." Order at 4. Even at the time this case was filed, the Company sought only a $5 million increase expected to be effective about March 1, 1998, about a 4% increase on core customers, and another 4.5% million effective January 1, 1999, about a 3% increase.[1] In July, BHE increased its request to more than $20 million effective in early 1998. At the end of the case, BHE's request has grown to more than $22 million, or about a 17% increase to core customers.

Thus, the financial turmoil the Company finds itself in has changed its strategy from rate status quo to rate increases of a magnitude that violate rate stability principles.[2] With the increase request growing from close to the inflation rate to one of over 17%, the level of customer opposition and unhappiness has grown. We have received many letters strongly objecting to the level of increase now sought by BHE. Similar sentiments were expressed at public witness hearings at Bangor and Machias.

III. TEST YEAR REVENUE REQUIREMENTS

In this section, we determine that the test year revenue requirement for the retail jurisdiction of Bangor Hydro-Electric Company should be $10,713,505. The summary of this calculation is contained in Examiner's Exhibit 1 and the details are shown on supporting exhibits related to the Company's test year revenue

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[1]The Company did have a $10 million temporary rate increase pending when this case was filed.

[2]The Company remarks, in its brief, that since the last overall rate increase in 1992, a 17% rate increase in 1998 would still be below the inflation rate over that time. The Company fails to note, however, that a fuel overcollection was owed ratepayers, that a rate benefit was owed ratepayers due to FAME financing of the Ultra Power QF contracts, that rate stability concerns should always give one pause before increasing rates 17% and finally, that BHE told its customers that its goal was no increase.

requirement. The cost of capital used in our calculation is 9.65% as determined in Section V. We reach our decision by incorporating into the test year results those adjustments that we find reasonable based on sound ratemaking principles, as we have articulated in our past decisions. In order to be included in the revenue requirement calculation, the proposed adjustment must have a strong likelihood of occurrence, i.e., be known, and must be capable of being measured with reasonable certainty. The standard that we will use, and the one that we have adopted in past cases, is the level of operations approach, wherein it is assumed that the initial rate effective year will reflect an operating level that is reasonably consistent with the test year, unless changes that affect the balance between revenues, expenses and rate base can be shown to have a reasonable likelihood of occurring.

The revenue requirement proposals of the Company and the parties have been in an almost constant state of flux since the very beginning of the case. The Company initially asked for a two-step increase consisting of $5.0 million at the conclusion of the case and an additional $4.5 million for effect on January 1, 1999. In addition the Company requested the implementation of a Maine Yankee adjustment clause that would permit a reconciliation of the Company's Maine Yankee-related costs. Shortly after the Company's initial filing, the owners of Maine Yankee decided to permanently close the plant. This, combined with the Maine Legislature's action regarding electric restructuring in the State, caused BHE to revise its request to a single adjustment of $20.6 million effective at the conclusion of the case. That amount was made up of test year deficiency of $22.1 million and an attrition adjustment of negative $1.5 million, which is more properly termed accretion. In its rebuttal filing, the Company once again revised its request to a test year deficiency of $18.34 million and an attrition deficiency of $3.77 million for a total requested increase of $22.11 million. Finally, at the hearings in the case, the Company's witnesses pointed out corrections and made further modifications to their recommendations. Following hearings, the Company submitted updated exhibits that indicate a test year deficiency of $19.164 million and an attrition requirement of $3.642 million, or a total revenue increase requirement of $22.806 million. When applied to core customers, as recommended by the Company, the rate increase equals 17.05%. The Company presented testimony on test year revenue requirements by Mr. David R. Black and Mr. Robert D. King, while its attrition recommendation was presented by Mr. Mathieu A. Poulin.

For the Staff testimony concerning test year revenue requirements was presented by Mr. Grant W. Siwinski, while testimony concerning attrition was presented by Mr. Kenneth F. Gallagher on behalf of the Staff. Finally for the Staff, Ms.

Angela Monroe presented a "Revenue Delta" sharing proposal. Mr. Gallagher's and Ms. Monroe's proposals are discussed in Sections IV and VI respectively of this report.

Staff's initial test year revenue requirement was $12.271 million and its attrition recommendation was a negative amount (accretion) of $4.081 million for a net recommended increase of $8.19 million. At surrebuttal Staff presented a required revenue increase of $10.249 million for the test year and a $1.496 million increase for attrition, resulting in a total revenue requirement increase of $11.745 million, prior to consideration of any sharing mechanism.[3] As did the Company, Staff filed revised exhibits after the close of hearings, and it also filed a further adjustment based on the Commission's decision of December 12, 1997, approving a §312 rate increase for BHE. Including the late-filed change due to the §312 decision, Staff now recommends a test year increase of $10.773 million and an attrition-related increase of $1.509 million, resulting in a total revenue deficiency of $12.282 million before consideration of any revenue sharing adjustments. After consideration of its revenue delta recommendation, Staff's revenue increase is reduced to $9.072 million, which when applied to core customers using Staff's recommended rate design methodology results in a rate increase of $8.347 million, or 6.22%.

For the Public Advocate, both test year and attrition testimony was presented by Ms. Lee Smith, who has, as her primary recommendation, advocated adoption of a price cap approach, by assuming the Company had been operating under such a mechanism during the test year. Her primary recommendation would have BHE's rates set to allow an increase no higher than the amount that would result if the Alternative Rate Plan (ARP) adopted for Central Maine Power Company (CMP) had also been adopted for BHE. Ms. Smith calculated an adjusted test year and compared the results with the bottom end of a range that is set at 350 basis points below the cost of equity of 10.56% that was granted in the Company's last base rate case. Ms. Smith also adjusted the allowed cost of equity to that recommended by Mr. Talbot for the Office of the Public Advocate (OPA) and used that as the basis for her lower bandwidth deficiency. Based on this calculation, she recommended an increase of $2.3 million be granted the Company. At surrebuttal Ms. Smith modified her test year numbers so that her primary recommendation was an increase of $2.441 million. At hearings, Ms. Smith presented an updated exhibit which showed her primary recommendation had changed to an

[3] Staff's revenue delta recommendation reduced the allowed increase to $9.282 million, and combined with its rate design proposal, Staff recommended an increase to core customers of $8.540 million, or 6.37%.

increase of $2.876 million, and this is the recommendation adopted by the OPA. We describe our reasons for rejecting this recommendation in Section VI.

Ms. Smith also conducted both a test year and an attrition analysis, which she presented, and has been adopted by the OPA, as an alternative to her primary recommendation. Like the Company and the Staff, the amount of her alternative recommendation has undergone several modifications since the beginning of the proceeding. At direct, Ms. Smith recommended a revenue increase of $11.2 million, which did not include any analysis of the effects of attrition. In surrebuttal, Ms. Smith presented a test year revenue deficiency of $11.435 million, an attrition adjustment of negative $4.781 million accretion, or a net increase of $6.876 million. At hearings, new exhibits were introduced that indicated a test year revenue deficiency of $12.074 million, an accretion amount of $3.870 million, and a resulting net revenue increase of $8.204 million. At briefing OPA presented a revised attrition exhibit that showed an accretion amount of $1.84 million and a resulting net revenue requirement deficiency of $10.235 million. Finally, in its reply brief the OPA maintains that the $10.235 million amount as the calculated net revenue deficiency, but also adopts for the first time a modified version of the Staff's revenue delta mechanism, so that his final recommendation is for a revenue increase of $9.007 million.

In the remainder of this section we will examine each of the test year adjustments proposed by the parties, and make a determination as to their inclusion into the Company's test year revenue requirement calculation. Initially, we will list the Net Operating Income (NOI) adjustments that are not in dispute, some of which have corresponding rate base effects, and then we discuss the disputed issues.

The following NOI adjustments are undisputed and will be included in the Company's revenue requirement calculation:

NOI # 1 Interest Synchronization

NOI # 2 Tax Adjustment

NOI # 3 Investment Tax Credit Amortization

NOI # 4 Prior Year Tax Adjustment

NOI # 5 RAR Adjustment (prior years' tax audits)

NOI # 6 Contributions in Aid of Construction Tax Adjustment

NOI # 7 Depreciation Adjustment (removes prior credit)

NOI #10 Veazie Property Tax Adjustment

NOI #11 Business Equipment Tax Reimbursement Program

NOI #12 FAME Interest

NOI #15 Low Income Program Amortization

NOI #16 Demand Side Management Cost Amortization

NOI #17 UltraPower Amortization

NOI #18 Off System Sales Adjustment

NOI #19 Long Term Debt Call Premium Adjustment

NOI #20 Pension Cost Adjustment

NOI #21 Lincoln Pulp & Paper Revenue

NOI #22 Key Bank Lease

NOI #23 Vehicles Lease

NOI #24 Post Retirement Medical Cost

NOI #25 PUC/OPA Assessment

NOI #28 Holtrachem Revenue

NOI #29 Insurance Cost

NOI #31 Penobscot Energy Recovery Company Amortization

NOI #32 SESCO Adjustment

NOI #33 Space Heating Revenues

NOI #36 “South Georgia” Tax Adjustment

NOI #37 Electric Plant Acquisition Adjustment

NOI #38 Environmental Tax Adjustment

In addition, adjustments 19 and 31 affect the Company’s rate base. The only other items where there is a dispute in the Company’s test year rate base are in the depreciation reserve, Beaverwood contract buyout, deferred income taxes related to depreciation, and working capital, which is directly related to the expense included in the overall NOI calculation. We will address each of the disputed adjustments individually.

A. Computer System Depreciation Period

The Company has installed three new computer systems to replace outmoded systems that had been in place for many years. The projects involve both hardware and software for the following systems: Financial Information Systems (FIS), Phases I, II and III; Customer Information System (CIS); and Geographic Information System (GIS), and will have a total depreciable basis of $12,661,571 when completed (Phase III of FIS is not scheduled to come on-line until December 1998). The parties do not dispute the amount or timing of the projects, but do disagree about the proper depreciable book life that should be used.

The Company asserts that because of the rapid changes that are occurring in the area of information systems, a life of 7 years should be used. It argues that even though parts of the previous systems lasted as long as 30 years, the new systems are likely to become technologically obsolete much more quickly. In arriving at its 7-year proposal, BHE informally surveyed other utilities that had installed new computer systems, discussed the matter with its outside auditors, and got input from its own systems analysts.

The Staff recommends that a 10-year depreciation life be used, because BHE itself admitted that 10 years was within the range of reasonable lives that it had identified. Staff also argues that when a reasonable range has been identified, the Commission should select a life that is at the high end of the range in order to mitigate the amount of required rate increase.

The OPA recommends that a 15-year life be chosen because the new systems are more flexible than those being replaced, allowing the Company to change the systems' configurations and usage characteristics without the necessity of complete replacement. In addition, OPA asserts that the informal phone survey and the discussions between BHE and its auditors do not support the 7-year life sought by the Company. As with Staff, OPA also argues that when there is uncertainty as to an asset's useful life, the Commission should select the reasonable life that moderates the required revenue increase to the extent possible. The OPA also argues that Phase III of the FIS should be excluded from rate base and from the depreciation expense calculation, because it is not scheduled to come on-line until December, 1998.

We find the Staff's recommendation to be a reasonable outcome of this issue. While it is true that technological advances have come with increasing regularity recently, we find unpersuasive the Company's argument that 7 years is the best estimate of the useful life of these new systems. We agree with the assessment of the OPA that the new systems will have increased flexibility, but we find that 15 years is too lengthy a recovery period. We also find that the manner in which the Company has calculated its rate base additions and depreciation expense is reasonable. BHE added Phase III of the FIS system to its rate base in December of 1998, so that it actually appears in only 1 month out of the 13-month rate base adjustment calculation. In calculating its depreciation expense adjustment the Company consistently used the mid-year convention, which means that in the year in which an asset is first placed in service a half-year of depreciation is taken no matter what the month in which actual usage begins. Thus, while we accept Staff's 10-year depreciable life, we have modified the depreciation reserve calculation (Exhibit 2-18) to agree with the amount expensed in 1998 of $1,148,953. This has the effect of slightly reducing the Company's rate base.

B. Computer System Efficiency Savings

With the introduction of the new computer systems discussed in Section 3.A above, the Staff and the OPA recommend that an adjustment should be made to reflect additional efficiency savings that will be generated by the new systems. The Company disagrees that any specific adjustment should be made, because it asserts that the O & M expenses projected for the rate-effective period are less than the trended levels, indicating that any savings have been implicitly reflected.

Staff argues that not all cost savings from the information systems have been reflected in the Company's budget and that the Company will experience productivity improvements that have not been taken into account. Because the Company was not able to identify specific areas of cost savings, Staff recommends the amount of annual support payments in the test year, $131,283, be used as a proxy for the estimated rate year savings.

OPA recommends that $350,000 be removed from the Company's expense total to reflect potential productivity savings from the new information systems. OPA bases its recommendation on information provided by the Company that showed the amount of potential savings expected to be generated by the three new systems. OPA asserts that the amount of its recommended adjustment is based on estimated savings from only the CIS system, as provided in the feasibility studies done before the project was approved, and not on the potential savings available from all three systems. Further, OPA argues that the amount from savings that could result from the installation of the CIS system may even exceed the recommended adjustment amount by a substantial margin. The OPA asserts that the savings are sufficiently known and measurable be included in the revenue requirement calculation.

We have examined the feasibility study documents entered as OPA Exhibit 23, and find that the Company did expect a substantial reduction in expenses from the new systems, and we find that those savings have not otherwise been reflected in its attrition projections. While the documents show a range of potential savings, we will use the low end of the cost displacement benefits, about $250,000, as shown on page 16 of the CIS Replacement Project Findings, dated June 6, 1994. We reject the Company's contention that analyses done 3 years ago are no longer valid, for if that analysis has changed, BHE had the responsibility of providing the updates to the record. Further, the amount of savings that we use may actually be understated, given that the Company's own feasibility study showed the possibility of much greater savings, and given that we are using only savings from the CIS system. The Company should not expect ratepayers to pay a return of and on these new systems without some offsetting benefits also being reflected in rates. We find that an expense adjustment of $250,000 should be included in revenue requirements to reflect these savings.

C. <u>Depreciation of Intangible Assets</u>

The OPA raises an issue concerning the amount of depreciation expense that BHE included in the test year as compared with the amount shown on its FERC Form 1. OPA asserts that the Company has double-counted the amount of depreciation adjustment needed to account for the new computer systems, and recommends that $346,778 be removed from the Company's test year depreciation expense to account for this alleged double-counting. The Company counters that the OPA has misinterpreted the test year depreciation expense amount, and that the amount included for new information systems in NOI Adjustment # 9 is not a double-count, but in fact reflects projects closed to plant in service after the test year. Staff has not commented on this matter, but has accepted the Company's amounts.

We find that no adjustment should be made, because the Company has sufficiently supported its contention that no double counting is present. The Company's adjustment for new information systems appears to entail events that occurred after the test year.

D. <u>Depreciation Overaccumulation Return</u>

The Company identified an overaccumulated balance in its depreciation reserve and revised its depreciation rates in its last base rate case, Docket No. 93-062, but due to a lag in implementing the new rates, its accumulated depreciation account now has an overaccumulated balance of about $3.5 million. The Company's has offered two alternative recommendations regarding the appropriate period of flowback. The Company's primary recommendation is to flow back the amount over 5 years beginning in January 1997. See Black/King Exhibit B/K-2-20 Rebuttal. As an alternative the Company recommends that the period of flowback be timed to end with the completion of the amortization of the Beaverwood contract buyout costs, which is February 2003, so that the alternative proposal would apparently have the return of the depreciation overaccumulation begin in March 1998. Either of the Company's proposals appear to entail a 5-year period for the return of the excess reserve, or an amount of about $712,000 annually. The Company argues that its proposal best serves the purpose of rate stability . The Company also argues that should the Staff's and OPA's recommendation be adopted, the Commission should assign some of the flowback to the 14-month period between the end of the 1996 test year and the date (March, 1998) when new rates from this proceeding are implemented. This would appear to result in a 38-month flowback period for the overaccrual.

The Company argues that amortizing the overaccumulated depreciation over a longer period (38 or 60 months) would avoid requiring a rate increase of $1.8 million for the T&D company at the time that retail competition is implemented (March 1, 2000). BHE Brief at 20. In addition, since the purpose of granting a $5.1 million increase in temporary rate increase was to strengthen the Company's cash flows it may be reasonable to treat the resulting overaccumulated depreciation reserve in a way that does not decrease the Company's cash flows by about $1.0 million during the rate effective period. *Id*. at 20.

Staff and OPA each recommend that a 2-year flowback be adopted, beginning in March, 1998 and ending at February, 2000, the date when retail electric competition is due to begin in Maine. The Staff argues that the shorter flowback period is one way to moderate the amount of rate increase required, while the OPA asserts that the 2-year flowback will result in the depreciation balances that are essentially correct at the onset of retail competition.

We find that the overaccumulated depreciation reserve should be flowed back to ratepayers over a 2-year period beginning when new rates resulting from this proceeding take effect. This will result in an annual flowback of about $1.781 million. We find that ratepayers should receive the benefit of this overaccrual as soon as possible, and that the intent of having the Company's account balances reflect the proper depreciation reserve at March, 2000, is a sound objective. In theory, ratepayers should have received the benefit of lower rates through reduced depreciation expenses for several years, and the 2-year return of the overaccrual is a reasonable method of making up that difference. Further, we will not assign any of the reserve flowback to periods prior to the implementation of rates in this proceeding. Doing so would merely increase the Company's reported earnings for that period, and ratepayers would be deprived of some portion of the benefit to which they are entitled.

We note that while we accept the Staff and OPA recommendation for this adjustment, we have modified the Staff's exhibit that shows the rate base effect of the flowback (Siwinski Exhibit GWS-2-20, Surrebuttal Revised). In the Staff exhibit the flowback is shown to start in January of *1997*, and would thus end in February, 1999. The effect of this is to overstate the rate base by using the *second* year of the reserve flowback in the Company's allowed rate base, as opposed to the first year if the flowback were calculated to begin in March, *1998*, as we have decided is proper. After consideration of deferred taxes, our modification reduces the Company's rate base by approximately $1 million from that proposed by Staff.

E. Beaverwood Amortization

This adjustment arises from the Commission's decision to allow the Company a §1322 rate increase of $5.0 million on an annual basis beginning in July, 1997, in Docket No. 97-201. In that decision the Commission ordered the Company to increase the annual amortization of its deferred Beaverwood contract buyout costs by the same $5.0 million that was allowed into rates, thus making the increase earnings neutral. On December 12, 1997, in the instant proceeding the Commission ordered a §312 increase of $5.0 million as an undisputed amount. This increase superseded the §1322 increase of Docket No. 97-201, so that the Commission also ordered the end of the accelerated Beaverwood amortization, thus converting the rate increase ordered in Docket No. 97-201 into an earnings effective amount. As of December 12, 1997, the Beaverwood amortization reverted to its previous level, and that amount will remain in effect until changed by the Commission.

The Company recommends that the balance of unamortized Beaverwood costs at March 1, 1998, simply be amortized over the remaining 5 years of the original amortization period, ending on February 28, 2003. The Company argues that its recommendation will result in better rate stability and improved cash flow for the Company, while the Staff position will require that a rate increase occur at the time that retail competition begins in Maine, and will not be as helpful to the Company's cash flow situation. The Company's recommendation results in a reduction of test year expense of $450,000.

Staff recommends that Beaverwood amortization be calculated to return the balance to the amount it would have contained at March 1, 2000 had the §1322 increase not been granted in July, 1997. This would reduce the test year expense by $1.125 million and be less than the Company's proposed amount by $675,000 annually, thus resulting in an unamortized balance that is $1.350 million higher than would result under the Company's proposal at March 1, 2000. OPA offered no independent analysis of this issue but supports the Staff position.

While we recognize that a larger balance at the time retail competition begins may have disadvantages, we find that moderation of the amount of rate increase to be passed on to customers in the interim is a higher priority. Prior to the start of retail competition, we will examine all of the Company's revenue requirements and stranded costs and decide on the appropriate period over which those amounts will be recovered. Therefore, we adopt the Staff's proposal to adjust the amortization of the Beaverwood contract buyout costs so that the balance at March 1, 2000, equals the balance that would have occurred under the original amortization schedule.

F. Maine Yankee Refueling Outage

The Company included this adjustment in the recommendations put forth by Mr. Jeffrey A. Jones in his testimony regarding the Company's overall level of purchased power expense. It is discussed in this section because the Staff recommendation for its treatment was presented by its witness on test year adjustments, Mr. Siwinski. We discuss the remainder of the Company's purchased power expenses in Section IV of this Report, and as they were presented in the testimony of Mr. Jones for BHE, Mr. Gallagher for the Staff and Ms. Smith for the OPA as part of their attrition analyses. The entire adjustment for purchased power, however, is included in the test year revenue requirements calculation and exhibits.

As part of its Purchased Power costs the Company has requested that an amount of $187,000 annually be included to amortize over 10 years the refueling outage costs incurred by Maine Yankee from February, 1997 through August, 1997, when the owners decided to permanently close the plant. The Company also seeks an accounting order that would allow it to continue to defer these costs as regulatory assets. When Maine Yankee was operating, it would provide to its owner utilities an estimate of the amounts that were spent above normal maintenance during its scheduled refueling shutdowns. Maine's three investor-owned utilities were permitted to defer these outage costs on their books and amortize them ratably over the period between refueling outages, usually a time span of 18 or 19 months. The theory is that costs should be smoothed to the extent possible, which would avoid the problem of having to adjust a test year for a "normal" amount of Maine Yankee operating costs, depending on whether a scheduled shutdown was, or was not, included in that year.

When the plant was operating normally, this practice worked relatively well for all three utilities. But, in December, 1996 Maine Yankee went off line in an unscheduled shutdown due to concerns about instrument cable routing and other safety concerns. In February, 1997, the plant's operators recognized that the unit would have to be shut down for an extended period, so they decided to proceed with replacement of some of the fuel assemblies and with other maintenance items that would usually be done during refueling outage. Under its normal schedule, the refueling would not have started until September, 1997, but it was decided to take advantage of the unscheduled safety shutdown to perform work that would usually have occurred during refueling. The strategy was that the plant would be refueled and ready to resume operation as soon as all safety concerns were addressed. In the summer of 1997, the strategy changed, and in August the owners decided to permanently cease operations at Maine Yankee.

In accordance with prior practice, Maine Yankee provided its owners with an estimate of the incremental refueling outage costs that were incurred in anticipation that the unit would restart some time in the late summer or fall of 1997. The total is approximately $43.0 million, and BHE's share is about $2.7 million, which the Company began to amortize over a 19-month period in September, 1997. The Company now proposes that the remaining balance at March 1, 1998, of approximately $1.87 million be declared to be a regulatory asset and be written off over a 10-year period. With a return on the unamortized balance, the annual revenue requirement is about $300,000. The Company asserts that these costs were incurred in anticipation of Maine Yankee's coming back on line, and recovery should be allowed based on the prior practice of amortizing the amount between scheduled outages.

Staff and OPA both reject the Company's proposed adjustment. Staff asserts that the costs no longer fit the criteria for normalization, and they cannot be classified as extraordinary costs. Ratepayers will receive no benefit from these deferred expenses, since the plant is no longer operating. Further, incurring the costs in anticipation of a restart was a choice the Company, as an owner of Maine Yankee, made on its own, and thus it must live with the consequences. OPA essentially agrees with the Staff's arguments.

We find that the Company should not be allowed recovery of these costs, and no regulatory asset can be established. We find the arguments of the Staff dispositive of the issue, in that the owners of Maine Yankee, at the time they decided to go ahead with refueling outage-type of maintenance items, took the risk that the plant would not resume operation, and so it is the owners who must bear responsibility for their actions. We are fully aware that the Company's rather precarious financial situation may be exacerbated by the write-off of this amount, but financial need is not a sufficient reason for converting non-recoverable costs into costs recoverable from ratepayers.

G. Electric Water Heater Program

In its direct case the Company removed the costs associated with its CareTaker program from its regulated accounts. The Staff and OPA agree with this adjustment, but in addition the Staff recommends that all revenues and expenses associated with the Company's Electric Water Heater Service program be moved to below-the-line status. This entails revenues of about $70,000 in the test year and expenses, net of a tax credit, of about $123,000, for a net increase to operating revenue of about $53,000. Staff asserts that this treatment is in keeping with the Commission decision in Docket 96-053, the *Cochrane* Order, which required that BHE account for non-core utility activities below the line, and that the water heater service program is not a core activity according to the definition put forth by the Commission in its current proposed rule, Docket 97-886.

The OPA recommends that $121,883 in administrative and advertising costs associated with the water heater program be removed from the Company's test year expenses, under the theory that the program operated at a loss, and thus, ratepayers are subsidizing the program. OPA asserts that the overhead costs of the program are disproportionately high and thus should be disallowed. The OPA also argues that the program is a non-core activity, and all revenues and expenses should be accounted for on a non-regulated set of books. The OPA asserts that this is not possible in the instant case, because BHE has not allocated any indirect costs to the water heater program. Therefore, OPA recommends the removal of about $122,000 from test year expenses.

The Company attempts to rebut the other parties' arguments by asserting that there are differences between its CareTaker and water heater service programs. It claims that the water heater program is related to the Company's primary business of selling electricity, and that it provides increased customer satisfaction, thus encouraging customers to continue to use electricity for water heating. Also, the Company points out that the *Cochrane* Order did not require it to put programs of this type below the line.

We will adopt the treatment proposed by the Staff, and remove from the test year all revenues and expenses identified by BHE as being associated with the Company’s water heater service plan. In our current Rulemaking proceeding we have proposed a definition of core utility services that clearly would not apply to the water heater service program. This service plan has nothing to do with the customer service functions that are included in the definition of core services. It is clearly an adjunct competitive service that does not qualify as a core service, and so it should be accounted for as non-regulated . We will accept the Staff’s calculation of the amounts that should be removed from the Company’s regulated books.

H. Normalization of Early Retirement Costs

The Company proposes that it be allowed to increase its test year expenses by about $493,000 to account for a normalization of early retirement program costs. The Company claims that its early retirement programs fit the criteria set forth by the Commission for normalized recovery, that is, expenses related to events that occur on an irregular but not unexpected basis. The Company asserts that it has conducted three such programs in the past 6 years, and that ratepayers will enjoy the benefits of those earlier programs in the rate effective period, presumably through lower labor costs. The Company further argues that equity considerations weigh in favor of including a normalized amount in rates for early retirement programs, since shareholders have borne the costs of previous programs, but ratepayers are enjoying the benefits. The Company determined its proposed adjustment amount by calculating the average of its three most recent early retirement programs and normalizing the average over 5 years. With this calculation, the Company asserts that it is almost certainly understating the likely cost of any future programs.

The Company also argues that the fact that it does not have specific plans for a future early retirement program should not be a bar to inclusion of this type of adjustment. BHE claims that given its current financial situation, it is highly likely that it will conduct an early retirement program prior to the year 2000 in order to accomplish the needed cost-cutting that will allow the Company to remain financially viable. Because the Company’s proposed adjustment uses a 5-year normalization period, and because its last early retirement program occurred in 1995, any program implemented prior to 2000 would meet the 5-year assumption used in its calculation. Finally, BHE asserts that Staff’s argument that the Company is attempting to engage in retroactive ratemaking should be rejected, because the Company is not proposing to account for any past program costs, but rather wants recognition of the fact that these costs are quite likely to recur sometime in the near future.

Staff argues that the Company is attempting to amortize costs that occurred prior to the test year, and thus, it is attempting to engage in a form of retroactive ratemaking. Staff also asserts that the amount of the expense is not known and measurable, and the Company has not included recognition of any cost savings that will result from such a program in its revenue requirement.

OPA bases its opposition to the proposed adjustment on the fact that the Company has admitted it has no specific plans for such a program in the immediate future. Allowing the proposed adjustment to expenses into rates would violate the matching principle in that offsetting benefits are not accounted for. OPA argues that the possibility that an early retirement program will occur is not sufficient to meet the known and measurable standard.

While the Company has presented several plausible arguments for including an adjustment for normalization of its early retirement program expenses, we reject the proposal as being too speculative, and as not meeting the expense/benefit matching principle. The Company's claim that this type of program is likely to occur is not strong enough evidence that a normalized amount should be included in rates to account for that possibility. Neither has the Company provided support for its claims that shareholders have entirely borne the cost of previous programs, or that ratepayers have enjoyed and continue to enjoy the benefits of the previous programs. Some amounts for this expense may have been included in previous revenue requirement calculations, and the Company has been operating under an implicit "stay-out" for the past several years. So while its earned returns may have been less than satisfactory, those results may have been even worse had any savings caused by implementation of early retirement programs not been present. In addition, we would expect any future early retirement programs to pass a cost/benefit test, so the Company has the opportunity to "fund" any future programs with future savings.[4]

We will be examining the Company's revenue requirement as a wires company prior to the start of retail competition, and at that time the Company may present evidence of the existence of

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[4]In the last rate case for NYNEX (Docket No. 94-254), we looked at both the costs and benefits of process reengineering for the Company, which included costs similar to early retirement program costs. NYNEX Order (94-254) at 39. Because the evidence permitted estimates of both the costs and benefits, we allowed NYNEX to recover its normalized process reengineering costs/benefits over eight years. In this case we lack reliable data on the benefits of early retirement programs so we cannot use that approach.

early retirement plans. Alternatively, early retirement program costs, if they meet the criteria for “exogenous” cost treatment, could be included in the 1999 Annual Review under BHE ARP, which we discuss below.

I. Amortization of Retiree Death Benefits

Only one relatively minor issue remains with regard to the accounting for retiree death benefits on the Company’s books. Staff proposes that $70,000 in test year costs be removed from the Company’s revenue requirement, while the Company claims that an adjustment of only $43,000 should be made. The difference relates to the “interest” expense included in the FAS 106 calculation of the death benefit liability.

As we understand it, the term interest in this context relates to the increase in the recorded liability due strictly to the passage of time. It does not relate to money earned on some cash balance. Thus, as with the remainder of the FAS 106 expenses recorded in the test year, we find that it should be removed from the Company’s allowed expenses and therefore we accept Staff’s adjustment.

J. New Employees Wages and Payroll Taxes

The Company proposes an adjustment to account for salary and wage increases for its current employees, as well as to account for seven new hires that it claims it must add in order to meet its monthly meter reading commitments (five new employees) and in order to support its new information systems (two employees). The Staff accepted BHE’s adjustment, but the OPA contends that the Company failed to show that the seven new employees actually will be hired during the rate effective year. The Company counters that the employees actually had been hired by the end of 1997, well before the start of the rate year.

We find that the Company has sufficiently supported its claim that the costs for seven new employees should be allowed as an adjustment to its revenue requirement, as well as the increased payroll costs associated with all other employees. We accept the Company’s proposed adjustment.

K. Advertising and Marketing Expenses

The Company proposes to remove $274,575 in test year expenses related to advertising for the Company’s space heating program and for trade show advertising. The Staff accepted the Company’s adjustment, but the OPA recommends that an additional $296,858 be removed, because the activities covered by those costs are promotional in nature. The Company argues that the proposed disallowances are arbitrary, and that most of the spending relates to customer information type of activities, and not to promotional activities.

OPA Exhibit 29 presents a list of expense categories for advertising and promotional work done by Garrand and Company for BHE. The list does not explain precisely what each category entails, nor does it provide details of the types of activities that are covered under each topic. While some of the categories have titles that sound like they might be promotional in nature, without a better understanding and analysis of the actual programs involved, we will not accept the OPA's proposed adjustment. The Company should be thoroughly familiar with Commission rules regarding promotional activities and spending, as contained in Chapter 83 of our Rules, and we find no evidence that the Company has misclassified or misrepresented any of its spending. While the Company retains the burden of proving its spending is properly categorized, the OPA has not presented sufficient evidence to lead us to conclude that BHE has included improper expenses in its revenue requirement. The nature of the activities themselves, not their titles on an itemized statement, determine whether or not the associated expenses should be allowed in rates.

IV. ATTRITION

A. Overview

In this section we determine that Bangor Hydro should be allowed an adjustment to its retail revenue requirement to account for attrition in the amount of $2,508,860. This amount has been adjusted to account for the difference between the test year and the rate year level of sales and includes consideration of a revenue delta adjustment as described in Section VI. The details of the calculation are shown on Examiner's Exhibit ATT-1 and the supporting attrition exhibits.

In Section III we discussed our findings concerning the Company's test year revenue requirements. In this section we examine the Company's earning capacity in the rate-effective period. If the balance between the Company's revenues, expenses and rate base are shown to have a high likelihood of changing from the adjusted test year levels, attrition or accretion is said to occur. When a utility's probability of earning its allowed return is reduced, attrition occurs. When the probability exists that the utility's earning capacity will be increased, the situation is known as negative attrition, or accretion.

The identification of attrition or accretion is a complex process that is easier to define in concept than it is to quantify in practice. The standards that we apply to adjustments in the attrition analysis are slightly different than those applied to test year adjustment, where a strict known and measurable standard is observed. In an attrition analysis, the degree of precision by which proposed adjustments are evaluated and measured must, by their nature, take into account the lesser degree of certainty that surrounds projections of the items involved. An attrition analysis looks at a future period, the first rate effective year, and tries to project, using educated estimates and forecasting mechanisms, how that future will affect the operations of the utility. In other words, it tries to determine if there will be a change from the test year level of operations that would reduce or enhance the utility's ability to earn its authorized return. Because an attrition examination is based largely on projections, greater caution must be applied when deciding whether or not to include an adjustment in the Company's revenue requirement calculation. Of course, the line between a known and measurable test year adjustment and an attrition adjustment is not a bright one, and each proposed change must be examined individually.

The starting point for the attrition analysis is the adjusted test year results, as we determined in Section III. Many of the proposed attrition adjustments use the test year adjusted amounts as their base, because attrition is used to discern changes from those levels that are likely to occur in the rate year. In their presentations, the parties have addressed the issues surrounding the Company's purchased power expenses in their attrition analyses, but have incorporated the results in the exhibits and calculations of the test year revenue requirements, and we have done the same. As with the test year, a considerable number of attrition issues are no longer in dispute, and we will accept them for inclusion into our attrition determination.

B. <u>Sales Forecast</u>

1. <u>Overview of BHE and Staff Forecasts</u>.

BHE's sales forecast was prepared by Roger Cooper, the Company's Load Forecasting Analyst, with supporting testimony from Dr. George Criner, of the University of Maine. Staff's sales forecast was prepared by Dr. Steven Estomin, of Exeter Associates, a consulting firm in Maryland.

The forecast methodologies used by Cooper and Estomin differ considerably. Cooper develops his Residential and his Commercial & Industrial (C&I) forecasts using a complex time-trend approach. In the Residential forecast, he first uses an econometric model with weather, income, and price variables to estimate coefficients for heating degree days (HDD) and cooling degree days (CDD). These are then used to weather normalize actual sales per customer. He then fits a trend line to a 4-quarter moving average of weather normalized actual sales per customer. This line is extrapolated to project future sales. These projections are then adjusted to remove projected future DSM, to reflect projected increases in electric heat sales, and to account for expected changes in sales due to the effect of federal appliance efficiency standards. The effect of the latter two adjustments is to increase forecasted sales. The result is a forecast of weather normalized sales per customer. The number of customers is also forecast by extrapolation. Overall residential sales are the product of forecasted sales per customer and the forecasted number of customers. The procedure for the C&I forecast is similar and will not be further described, since only the Residential forecasts are disputed at this point in this proceeding. There are also forecasts of Wholesale and Lighting sales, which have never been disputed in this proceeding.

Estomin uses “causal” econometric models to forecast Residential and C&I sales. For the Residential model, his variables are price, income, and weather, as well as actual sales during the corresponding quarter of previous years. In addition there are three “dummy” variables, including one that is a second price variable intended to capture the effects of rapid price increases believed by Estomin to have occurred during the early 1980s. The C&I model is similar, although it lacks the dummy variables.

The results of these two forecasts for the rate year (ending February 1999) are presented and compared in Table 1 of Cooper’s Rebuttal Testimony. BHE predicts a 1.06% increase from 1996 to the rate year, while Estomin predicts a 5.85% increase. Cooper Reb. Test. at 2.

Table I			
Forecaster Sales			
For Year Ending February 1999			
(Thousand of MWH)			
Class	Bangor Hydro	Dr. Estomin	Difference
Residential	537.2	565.2	28.0
Commercial	517.8	540.9	23.1
Industrial	167.0	174.2	7.2
Paper Mills	265.0	265.0	0.0
HoltraChem	227.8	227.8	0.0
Wholesale	4.5	4.5	0.0
Streetlighting	8.9	8.9	0.0
Total Sales	1,728.2	1,286.5	58.3
Total less HoltraChem and Paper Mills	1,235.4	1,293.7	58.3

In his Surrebuttal Testimony Estomin withdrew his C&I forecast and accepted the Company's. He also updated and revised his Residential forecast, incorporating actual sales for the second and third quarters of 1997, and removing the effects of errors in the price data inputs during the early 1980s. These changes leave residential sales the only disputed forecast between BHE and Staff, and they greatly reduce the amount of the difference in overall forecast. The difference in the Residential forecast is reduced by 11,500 MWH. A table in BHE's Brief (p. 37) illustrates the remaining differences between these parties, providing forecasted sales and growth rates from the preceding year for 1997 and the rate year, as well as some history on Residential sales.

Residential Sales History and Forecasts		
Sales in MWH		
	MWH	Growth Rate
1989	528,574	
1990	526,926	-0.3%
1991	523,219	-0.7%
1992	528,066	0.9%
1993	521,412	-1.3%
1994	522,634	0.2%
1995	518,194	-0.9%
1996	536,490	3.5%
Cooper 1997	528,950	-1.4%
Estomin 1997	537,113	0.1%
*Cooper 1998	537,163	1.3%
*Estomin 1998	554,723	2.8%
Source: Cooper Prefiled at Table 4, Page 6 and Tables 2 and 3, Page 4; Estomin Prefiled Surrebuttal at 3, as revised. *Rate effective year 98:03-99:02		

Comparisons with Service Territory Data and Major Forecasts.

In his Direct Testimony Cooper presented a number of major national and regional forecasts that appear to be inconsistent with Estomin's forecast of 5.83% growth in overall sales between 1996 and 1998. These include the Energy Information Administration (EIA), NEPOOL, and the North American Electric Reliability Council (NERC).

NEPOOL forecasts regional growth of overall sales between 1996 and 1997 of 1.10%, and growth between 1997 and 1998 of 1.50%. NEPOOL projects overall growth of 6.2% for the region over 5 years. BHE points out that Estomin, predicting 5.83% growth over 2 years, expects BHE sales to grow more than twice as fast as the regional average. BHE argues that this is especially surprising when one considers that social and economic drivers in Maine are generally less favorable than in the rest of New England, and in BHE's service territory they are generally less favorable than for the rest of the state.

NERC projects 5.58% overall growth for the Northeast over the next 5 years. Estomin predicts growth in BHE sales to be 2.5 times faster than NERC's projection for this region. Similarly, EIA projects overall growth at an average of 1.6% per year in the nation.

BHE points out that it has seen a total 6.10% growth in core sales between 1990 and 1996, meaning that it took BHE more than 5 years to grow sales as much as Estomin forecasts for 2 years. BHE's average annual growth in overall core sales since 1990 has been about 1%. Average residential growth has been 0.3% per year during the same period.

BHE states that with sales through August 1997 showing a 1% increase there is little chance that Estomin's 3% increase for 1997 will be achieved. If the increase for 1997 is 1%, the increase for 1998 would have to be about 5% for Estomin's 1998 forecast (Direct Testimony) to be achieved. Given data for the first 11 months of 1997, 1998 residential sales would have to grow at 3.35% to achieve Estomin's Surrebuttal estimate for the rate year.

In general, BHE argues that Estomin's forecasts are not plausible in the light of other major forecasts, current and past sales data for BHE, and social and economic drivers for BHE's service territory. We agree, and we note that in his Surrebuttal Testimony Estomin agrees with this assessment of his Direct Testimony forecast.

2. Approach to Model Development

Cooper states that he used econometric models so long as they worked, but noticed that they began overforecasting during 1992. A Chow test confirmed a structural change at that time. Cooper's assessment was that available econometric models do not account for the effect of federal appliance efficiency standards. He could find no remedy for this deficiency and in 1995 began to experiment with time-trend forecasts, which appeared in short-term forecasts to better account for the sales data.

Staff and OPA argue that causal econometric models are theoretically superior to time-trend models, because they capture the underlying causal processes and are therefore better able to reflect changes in important causal variables.[5] Time trend models will be less reliable when there are changes in underlying causal factors.[6] This much appears to be true, but it

[5]It appears that too much emphasis is placed on the value of "causal" econometric models. Specification error is present to some degree in all. Estomin admits as much when he states that an econometric model "is not designed to replicate reality."

[6]OPA faults Cooper's time-trend approach on the grounds that it is too dependent on the assumption that the future will be like the past. This assumption, of course, is a familiar informal statement of the epistemological principle of induction,

doesn't follow that a causal model that is performing poorly (even if it has "good statistics") should be preferred to a time-trend model that is performing well. Dr. Estomin recognized this when he decided to abandon his causal C&I model in favor of BHE's time-trend.

BHE argued that population, income, and business data for its service territory do not support assuming any major changes in causal factors underlying electricity sales in the short term. Criner supported this assessment. OPA appears to argue for the possibility of a major economic upturn, but the basis for this is unclear, and this expectation is not consistent with the information on the local economy reviewed in BHE's Direct Testimony. It is true that BHE has not taken into account the effect on sales of its expected rate increase, but this would have the effect of decreasing its sales forecasts.

As argued by Criner, time-trend forecasting is a useful and widely accepted tool. It can be especially helpful in short-term forecasting where no satisfactory causal model can be found.

Criner argued that Estomin appears to have adjusted and reestimated his models, until he found a formulation that satisfied pre-set conditions. Estomin admitted this in his Surrebuttal Testimony . Criner argues that this procedure introduces a likelihood that the modeler will eventually discover spurious relationships, existing only as chance patterns in the data. We agree and find that in such a case a model's statistics, such as R^2 and t, can no longer be interpreted as supporting its validity.

We will adopt BHE's forecast in preference to Staff's for three reasons. First, we agree with BHE's assessment that Estomin's Surrebuttal Residential forecast is not likely to be achieved. Second, we are not convinced that Dr. Estomin's model has acceptable predictive power. Finally, we believe that the Company's model does a better job of predicting BHE's energy sales in the short-term.

We note that the record contains debate on many specific issues and modeling details, including the appropriateness of BHE's weather normalization, the proper modeling of seasonal prices, the proper modeling of weather, Estomin's use of a Koyck lag of the dependent variable, Estomin's

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which is presupposed in all inference in the empirical sciences. Examples of scientific work that avoid this assumption are difficult to find. Cooper makes a similar point when he states that Ordinary Least Square models are simply a linear combination of trend models.

use of a second price variable, and others. We make no finding on these issues, because we believe that the choice between forecasts can be made on more straightforward and fundamental grounds. In particular, there is no need to assess Cooper's criticisms of Estomin's models, since we already have sufficient grounds for preferring Cooper's. This is not meant to suggest that there are no respects in which Cooper's forecasts could be stronger. They are simply the more plausible of the two. Indeed, in practice even the best forecasts will have some theoretical or practical shortcomings.

3. Revenue Forecast

One final area of disagreement between Staff and the Company involves the level of sales revenue that should be included in the rate year for the James River Company (JR). This paper company has a special contract with the Company that is due to expire on December 31, 1998. The dispute between Staff and the Company concerns the rate at which James River will take service over the last 2 months of the rate year, that is, for January and February 1999. There does not appear to be any disagreement over the number of kWh that will be sold to JR.

The Company asserts that the current contract rate should be assumed to continue for the 2 months in question, because the contract contains an extension clause, and because JR has options other than purchasing from BHE. The Company asserts that it will have to provide a discount in order to keep JR as a customer, and there is no reason to believe that a new or extended contract will contain a higher rate than the present one.

Staff contends that in the absence of a new or extended contract, JR should be assumed to revert to the full tariff rate applicable to its class of service for those 2 months. Staff's proposal would add about $612,000 to the Company's estimated revenues for the rate year. Staff essentially makes two arguments in support of its recommendation: 1) it is not clear that JR will have an alternative to taking service from BHE for those 2 months, and so it is not clear that a discount contract would be appropriate or necessary; and 2) in the future the Commission may want to hold BHE entirely responsible for its decisions with regards to new or extended special rate contracts.

Staff claims that JR will not be able to install self-generation in time to be able to require a special rate contract by the end of 1998. Staff also points out that under the present AMP, which it assumes will stay in place, the Company could offer a new contract that would be subject to limited scrutiny if it met certain conditions. In that case, Staff suggests that the Commission may want to hold the Company responsible for its discounting activity. The Company counters that it would be short-sighted for the Company to be in the position of taking short-term advantage of its large industrial customers and running the risk of permanently losing JR and others who are in similar situations. The Company also claims that Staff now want the Company's shareholders to absorb 100% of all future discounts, which would surely decrease the Company's incentive to offer special contracts, and this in turn, would exacerbate the revenue shortfall that must be absorbed by the core customers.

This issue has no easy answer. We are made to speculate about what might happen in negotiations between the Company and one of its major customers 12 months from now. We find it quite likely that BHE will have to offer some discounted rate to JR in order to retain it as a customer, but we cannot be sure what the terms of that special contract will be. We will reluctantly adopt the Company's position, because of the probability that a special rate will be required. The best estimate that we can make is that the current contract will continue in effect for the full rate effective period.

Having determined that we will use the Company's sales forecast, we must turn that projection of rate year energy sales into a revenue forecast. In order to accomplish this, we will use the methodology presented by Mr. Gallagher in his Exhibit KFG-6-1, which uses a forecast of kWh sales and the class average rates from the test year to determine rate year sales revenue at current prices, then adds the amount of increase that we found appropriate in Section III. Thus, we find that the Company's base revenues for the rate effective period are estimated to be $174,693,297.

C. <u>O & M Expenses</u>

The Staff and the Company both assert that there is no difference in their positions regarding operations and maintenance (O & M) expenses in the rate year. The OPA argues that Staff witness Mr. Gallagher did not explain the reasons for his apparent change of position from his direct to his surrebuttal testimony regarding the attrition year level of O & M costs. Therefore, OPA recommends that the Commission remove approximately $1.0 million in O & M expenses from the attrition analysis.

Our review of the record leads us to conclude that there was no unexplained change in Mr. Gallagher's position, but that he did change the dollar amount of his proposed adjustment in order to agree with the revised amount proposed by the Company at the rebuttal stage. In fact, the Company has updated its amount after the close of hearings to reflect a change to the test year level that was used as the base for its proposed adjustment. We will accept the updated amount of $1,164,196 as the adjustment to the test year reasonable O & M level.

D. Maine Yankee Purchased Power Issues

While the specifics of the Company's purchased power costs are discussed in this section under the attrition analysis, the adjustment has been incorporated into the test year calculations and exhibits, except for the increase in purchased power expense caused by the forecasted increase in sales. That amount is included in Mr. Poulin's and Mr. Gallagher's attrition exhibits, and we will adhere to the method.

1. Maine Yankee Replacement Power

The Company and the Staff agree on the majority of issues related to the level of Maine Yankee replacement power costs for the rate year, and the OPA indicates that there is no additional dispute on this issue. The Staff, however, in its brief asserts that an additional amount of $344,000 should be removed from the replacement power expense, because FERC has not approved the Outside Transaction Adjustment (OTA) tariff that was included in Mr. Jones' estimate of the price of replacement power. An adjustment in this amount is apparently not reflected in the revised exhibits filed by the Staff on December 22, 1997, because the amount of replacement power expense shown on Exhibit KFG-9, $9,772,000, agrees with the amount on JJRBT-2 (Revised) from Mr. Jones testimony.

Because of the uncertainty regarding the ultimate approval of the OTA tariff by FERC, we will not allow it into retail rates at this time. As discussed below, however, we will allow the Company to defer any expenses paid during the rate effective year under the OTA tariff and seek recovery at the time of the annual rate adjustment that we implement in Section VII. We will, however, adjust the Staff's amount from $344,000 to $488,600, based on our understanding of the calculation. Based on Mr. Jones' estimate that the tariff had a 25% probability of being approved at FERC, he included (and the Staff seem to agree) an estimated rate of $1.44/MWh and an amount of replacement power of 349 Gwh in his calculation. The product of these numbers is $488,600, and that is the amount of expense we remove from the rate year projected replacement power costs.

Staff states that the amount of replacement power cost should be "bookmarked" for future identification, in case that any Maine Yankee costs are determined to have been caused by imprudence. Given the reconciliation mechanism that we adopt as part of the rate cap plan in Section VII, there is no need to "bookmark" the Company's replacement power costs, or any other costs associated with Maine Yankee. All these costs will be open to adjustment and reconciliation once the Maine Yankee prudence investigation has reached its ultimate conclusion and a final order has been implemented concerning cost recovery.

2. BHE's Share of Maine Yankee

The Company has claimed that the Massachusetts municipal and cooperative utilities have refused to continue to pay their share of Maine Yankee's ongoing expenses, and the Company assumes the same situation will occur with respect to Maine's two consumer-owned utilities that have shares in the plant. Because of this potential failure to pay, the Company has proposed an adjustment that would increase its share of Maine Yankee from 6.8998% to 7.0%, resulting in a net expense increase of about $100,000. The Staff and OPA oppose this adjustment because of its highly speculative nature. They argue that, first, there is no evidence the Maine consumer-owned utilities will follow the lead of the Massachusetts entities and refuse to continue to pay their required share, and second, that even if the customer-owned utilities actually stop making payments, BHE likely has legal recourse that it can pursue against them.

We agree with the OPA and the Staff regarding the highly uncertain status of this matter, and so we reject the Company's proposed adjustment.

3. Maine Yankee O & M

The parties have agreed that Maine Yankee's ongoing O & M costs should be subject to a deferral and normalization mechanism. The Staff further proposes that these costs should be subject to its proposed reconciliation mechanism as part of the annual review. The OPA warns that any reconciliation mechanism must be adopted under the terms of an incentive ratemaking plan adopted in accordance with §3195. The Company agrees with the Staff proposal, but claims that a rate plan is not required because a future adjustment could occur under the Supplemental Order Implementation Method (SOIM) that it recommends and that has been used in previous cases by the Commission.

While we adopt a normalization and reconciliation mechanism for all Maine Yankee-related costs, we must decide how much to put into rates at the present time, as this amount will affect the Company's cash flow and the amount that ratepayers will currently pay. There is basic agreement among the parties about the amount of Maine Yankee O & M that should be deferred and normalized. Staff recommends that $20.0 million of 1998 expenses be deferred and amortized ratably over the following two years. We find this to be reasonable and adopt the Staff's proposal. This expense is also included in the Maine Yankee reconciliation that we adopt in section VII.D.

4. Maine Yankee Fuel Costs

Staff also recommends that all fuel costs be removed from the revenue requirement calculation and be subject to a reconciliation mechanism, and the OPA agrees with the Staff recommendation. The Company agrees that a reconciliation approach is appropriate with respect to fuel costs, but proposes that $509,000 be included in rates to account for the amortization of the last core of fuel, other fuel indirect costs, and Maine Yankee's fuel disposal payments.

Staff argues that there are several uncertainties surrounding the fuel cost issue, including the fate of the fuel in the reactor, the problems that Maine Yankee discovered with all of the fuel rods obtained from one manufacturer, and the disposition of new fuel rods that were ordered but not installed in the reactor. Also, a suit has been brought against the Department of Energy by the owners of several reactors that claims that DOE should be responsible for damages for its failure to take delivery of spent nuclear fuel as required under federal law and under its contracts with reactor owners. In its brief Staff mentions this suit in the section regarding decommissioning, but it is equally relevant here.

We will accept the Staff proposal to exclude all nuclear fuel related costs from the Company's current revenue requirement calculation. The Company may defer any Maine Yankee fuel costs, and those will be subject to reconciliation in a future proceeding.

5. Maine Yankee Decommissioning

Maine Yankee currently has in its rates about $15 million in decommissioning costs, but based on updated information, it has estimated that it needs more than double that amount. Its new decommissioning study has been filed at FERC, and in fact, the FERC has allowed the new rates to become effective January 15, 1998, subject to refund while the reasonableness of those rates is litigated.

Here the Staff mentions the federal suit brought against the DOE regarding its failure to adhere to its contract to accept spent nuclear fuel, as well as the uncertainty regarding the entire issue of decommissioning. Staff also asserts that the amount of decommissioning expense has undergone numerous revisions since the case was originally filed. Finally, Staff supports its proposal to defer and reconcile these costs with the reasoning that the Commission has recently opened an investigation into the prudence of Maine Yankee's actions, and any increase to decommissioning expense should await the results of that proceeding.

The Company argues that the increase in decommissioning costs should be put into retail rates now, and if the FERC were to order a refund the Commission could issue an accounting order that would require the Company to defer the refund and eventually flow it back to ratepayers. The Company notes that the suit against DOE has not ultimately been decided, but only that specific performance has not been ordered and that the court ruled that monetary damages would be a sufficient remedy, and the court allowed the suit to proceed. The Company also asserts that denial of this expense will put additional cash flow pressures on it at a time when cash will already be tight.

Because of the many uncertainties involved, we find that the Company's proposal to include incremental decommissioning costs in its revenue requirement should be rejected. While we understand the Company's concern with its cash flow situation, we must also be concerned with the situation of its ratepayers who will be providing the cash to the Company in the interim. There are simply too many unanswered questions involving the ultimate amount of this expense to allow us to conclude that an increase should be built into current rates. Here again, the Company may defer any increased decommissioning costs that it incurs during the rate effective period, and seek recovery of those costs, as well as an adjustment on a going-forward basis, at the time of its 1999 annual review. At that time we will consider all of the issues concerning the recoverability of increased decommissioning costs based on the information that will be available at that time.

6. <u>Maine Yankee Property Taxes</u>

The Staff has proposed an adjustment to the level of property taxes to be paid by Maine Yankee in the rate year. Staff notes a recent agreement between the owners of the plant and the town of Wiscasset to reduce the level of property taxes to be paid during the 1998/99 tax year by almost $.9 million, which translates into a reduction of about $63,000 for BHE. The OPA supports the Staff recommendation, but the Company claims that the Staff misinterpreted the period for which the new tax level would be in effect. BHE claims that Mr. Jones adjusted his amount to take into account the fact that the new tax amount takes effect "in the second quarter of 1998." OPA Brief at 35. The Company cites OPA exhibit 38 as support for its position. That exhibit indicates the new rates will be in effect for the tax year running from April, 1998, through March, 1999, which, of course, is the second quarter referred to by the Company, but is only 1month after rates resulting from this proceeding are due to become effective. Also, we can find no record evidence of how Mr. Jones apportioned the revised and current property taxes between tax years to arrive at his estimate. Absent that calculation, we find the Staff's proposed adjustment to be sufficiently accurate to be included as an adjustment to the Maine Yankee expenses.

E. Off-System Capacity Purchases

After the Company's acceptance in its brief of the Staff proposal regarding the estimated price to be paid for the New Brunswick capacity purchase ($1.26 million), only one issue remains in dispute in the area of off-system capacity purchases. The remaining item concerns the price to be paid for the 30 MW of spot capacity that the Company estimates it will have to acquire during the rate year. Although there is debate about whether 30 MW is too much (Staff assertion) or too little (BHE assertion), the parties' disagreement essentially involves the price of the capacity.

The Company claims that it will have to pay $45/KWyr, based on the estimates of prices presented by its witness Mr. Jones. Staff witness Mr. Gallagher examined some recent bids received by the Company and suggests that BHE can acquire the needed capacity for about $40/KWyr. The Company claims the Staff is incorrectly looking at bids for a base load unit, when the Company will actually be purchasing dispatchable capacity, which carries a higher price tag. In addition, BHE asserts that a base load plant is usually bundled with energy, making it somewhat difficult to determine what an unbundled rate would be. Finally, the Company asserts that changes to NEPOOL rules may require it to carry a higher amount of capacity to meet its capability responsibility commitment. For all these reasons, the Company recommends that the Commission adopt Mr. Jones' estimate for the amount and price of spot capacity (i.e., above the 30 MW), and also, that the Commission subject this cost to the Company's proposed true-up mechanism.

While the evidence before us is far from conclusive, we will adopt the Company's position regarding the amount to be purchased and the price to be paid for spot capacity in the rate year, resulting in an increase over the test year of $1.018 million. We find the Company may have a slightly better understanding of the market than the limited examination of bids done by the other parties. We will not adopt a reconciliation mechanism for this expense category, but at the Company's 1999 annual review the Company and any other party who wishes to do so may present evidence to show that BHE's off system capacity purchases will be significantly different in subsequent rate effective years. This item will be treated as a True-Up Factor and therefore the $300,000 minimum for an Other Exogenous Cost does not apply.

F. Miscellaneous Purchased Power Expenses

In direct and rebuttal testimony Mr. Jones proposed an $800,000 adjustment to account for several potential increases to the Company's purchased power expenses during the rate year. The amount was based on assigned probabilities of certain changes that the Company claimed might occur, primarily with respect to NEPOOL rules and tariffs. While Mr. Jones assigned probabilities to the various expense categories, he based the amount of his recommended adjustment on 1% of the Company's test year total of fuel and purchased power expenses. At hearings, Mr. Jones presented a revision to his amounts and his methodology, by assigning specific probabilities to each of four individual expense categories and summing the probability-weighted amounts, resulting in a recommended adjustment of $1.235 million. The four expense category adjustments, their probabilities and weighted dollar amounts proposed by Mr. Jones are as follows: 1) NEPOOL congestion, or anti-hoarding, tariff, 25% probability, $.36 million; 2) NEPOOL Regional Network Service (RNS) Schedule 1, 100% probability, $.268 million; 3) RNS Schedule 2, 100% probability, $.296 million; and 4) NEPOOL/ISO budget expenses, 100% probability, $.311 million. In addition, the Company proposes to make NEPOOL-related capacity costs subject to true-up in one year.

Staff and OPA both urge rejection of the Company's attempt to include any of these costs in its revenue requirement calculation, because of the large amount of uncertainty that exists with each of the charges. They point out that FERC has suspended RNS Schedule 1 and RNS Schedule 2 has not even been filed yet. As for the NEPOOL/ISO budget amounts, these have not even been finalized at the ISO, much less filed at and approved by FERC, and there remains significant uncertainty as to what the total budget will be and how it will be apportioned among the participants. As for the anti-hoarding tariff, it also appears to be only a proposed charge, and even if it does go into effect, BHE has the ability to eliminate or mitigate it by selling its excess reserved capacity.

For all of the reasons put forth by the Staff and the OPA, we cannot accept the Company's proposal to include $1.235 million in rates when the items are based on probability estimates. Conversely, there is a reasonable chance that one or more of these charges will be adopted by FERC and be charged to BHE, and it seems the Company will have little influence over the ultimate imposition of the charges. Therefore, we will include in the Company's revenue requirement $300,000 to cover the likely probability that one or both of the RNS tariffs will be imposed and that some increase NEPOOL/ISO budget will be implemented. We will not allow anything for the NEPOOL anti-hoarding tariff, because the Company has the ability to reduce or avoid such charges. While we will not adopt a reconciliation mechanism for the amount we allow into rates, we will allow evidence to be presented at the annual review that would show that the Company's retail rates should be adjusted to recognize changes to the total amount of these NEPOOL-related rates that are likely to occur in subsequent rate-effective periods. Although we generally do not approve of single-issue rate adjustments, and our decision on these NEPOOL-related charges has some aspects of single-issue ratemaking, we believe that the prospective adjustment at the annual review is justified given the magnitude of the costs involved and the Company's relative inability to avoid the three items that we have described above. The costs are too uncertain to be fully included at this time, but we find that there is a sufficient probability that they will be imposed on the Company, and we allow $300,000 in rates for the attrition year, and we allow the possibility of adjustment at the Company's annual review if NEPOOL-related costs will be significantly different in subsequent rate effective years. This item will be treated as a True-Up Factor and therefore the $300,000 minimum for an Other Exogenous Cost does not apply.

V. COST OF CAPITAL

A. Summary of Positions of Parties

The Company seeks the opportunity to earn an overall rate of return on its rate base of 9.88%. Company witness Strong recommends that the Company's return on common equity (ROE) be 13.62%. This "all-in" cost of common equity includes a 43-basis-point adjustment for flotation costs.

Staff recommends an overall rate of return of 9.60% for the Company. Staff witness Kivela recommends that the Company's ROE be 12.75%, which is the midpoint of a range of 11.65% to 13.75%. This "all-in" cost of equity includes a 25-basis-point (or 3.7%) incremental adjustment for flotation or issuance expenses.

Public Advocate witness Talbot recommends an overall rate of return of 9.35% (using the Staff's capital structure) and a cost of common equity of 11.8%.

B. Background on the Cost of Capital

One of the steps necessary to determine the Company's overall revenue requirement is to determine a rate of return (ROR) that is applied to the Company's total rate base. While the allowed rate of return is generally referred to as the cost of capital, there is a distinction between the two concepts. Strictly speaking, the cost of capital is equal to the weighted average cost of the utility's capital (WACC). The WACC is equal to the sum of the costs of the components of the Company's capital structure, after each component is weighted by its respective proportion to the utility's total capitalization.

Judgment needs to be applied in arriving at the cost for each of the components of the capital structure. In particular, judgment is required to develop a forward-looking estimate of the cost of common equity. Our analysis of the cost of capital, especially with respect to the cost of common equity, sometimes implies a degree of precision that is not really present. Nevertheless, we must set an exact cost rate for each of the components and for the overall cost of capital to the utility.

The allowed rate of return which is actually multiplied by the rate base may contain adjustments to the cost of capital that reflect management efficiency or other considerations related to the balancing of ratepayer and utility interests. The overall rate of return must strike a balance between the interests of ratepayers, who are entitled to the lowest reasonable cost of service, and the utility, which is entitled to a rate of return that allows it to attract capital on a reasonable basis.

This relationship between the cost of capital and the utility's fair rate of return has been established by several familiar United States Supreme Court decisions. *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia*, 282 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944); and *Permian Basin Area Rate Case*, 390 U.S. 747 (1968). The Hope and Bluefield cases collectively establish the general principles that the return to common equity owners should be commensurate with the returns on other investments having corresponding risks and should be sufficient to ensure confidence in the financial integrity of the enterprise in order to maintain its credit and its ability to attract capital. In Permian Basin, the Court tempered the strict reliance on the returns paid to investors with acknowledgement that commissions must consider the "broad public interest" when making decisions on rate of return. *Id.* at 791.

The Maine Law Court has also required that the Commission consider the interests of ratepayers when setting the rate of return. Ratepayers' interests must be given substantial weight in the final determination of a utility's allowed rate of return. *New England Telephone and Telegraph Company v. Public Utilities Commission*, 390 A.2d 8, 30-31 (Me. 1978). In prior cases, for example, we have made cost-of-equity adjustments to account for utility inefficiency. We have generally used such adjustments when the effect of the inefficient behavior results from inaction rather than action. *See* e.g., *Bangor Hydro-Electric Company*, Docket No. 86-242, slip op. at 17-50 (Me. P.U.C., Dec. 22, 1987) (25 basis point reduction on equity because of management inefficiency in the credit and collection and conservation and demand-side management areas).

In this case, we have been presented with no evidence that would lead us to adjust the cost of capital for any of these types of concerns. Thus, we can and will use the terms "cost of capital" and "rate of return" interchangeably.

C. Cost of Common Equity

1. Dr. Strong’s Analysis

Dr. Strong’s recommendation of a 13.62% ROE for BHE was based on his subjective weighting of three methodologies: (1) a 13.25% ROE estimate based on a historical risk premium approach; (2) a 13.12% ROE estimate based on a peer group (Northeast Utilities and Central Maine Power Company) discounted cash flow (DCF) analysis; and (3) a 11.92% ROE estimate based on a BHE-specific capital asset pricing model (CAPM) analysis, which used historical inputs. On rebuttal, Dr. Strong gave a greater weighting to his historical risk premium and peer group DCF results; in his direct testimony he had equally-weighted his three methodologies. Table 1 summarizes the recommendations that Dr. Strong supported during the rebuttal phase of this case.

Dr. Strong then made a flotation cost adjustment of 43 basis points and an upward “subjective adjustment” of 26 basis points, which resulted in his 13.62% ROE recommendation.

Table 1: Summary of Dr. Strong's Recommendations

Methodology	Result	Weight	Weighted Average
Historical risk premium	13.25%	40.00%	5.30%
NU/CTP DCF Model	13.12%	40.00%	5.25%
CAPM w/ Beta of .8	11.92%	20.00%	2.38%
Weighted Average ROE		100.00%	12.93%
Flotation Adjustment			0.43%
Subjective Adjustment			0.26%
All-In Total ROE			13.62%

Source: Exhibit RKSUR-13.

2. <u>Mr. Talbot's Analysis</u>

Public Advocate witness Talbot's ROE recommendation of 11.8% is based on four separate DCF analyses (two variations on two peer groups) and he checked his results with a CAPM analysis using the average beta from the same two peer groups as a proxy for BHE's beta. Mr. Talbot deemed one of his peer groups to be "more-comparable" and one to be "less-comparable." Assuming that BHE was more risky than the "more-comparable" group, Mr. Talbot extrapolated a 65 basis point premium to the top of the DCF result derived for the more-comparable group to calculate an 11.85% ROE, as shown on Table 2, which he then rounded to 11.80%. Mr. Talbot's "all-in" cost of equity recommendation of 11.80% includes a flotation cost adjustment of 5.6%, or 35 to 40 basis points, based on the Commission's most recent rate case (Docket No. 93-062) involving BHE.

Table 2: Summary of Mr. Talbot's DCF Recommendation

	High Estimate	Low Estimate	"Best" Estimate
Less-Comparable Group	10.77%	10.29%	10.53%
Extrapolation factor			0.66%
More-Comparable Group	11.85%	10.53%	11.19%
Extrapolation factor			0.66%
Recommended ROE			11.85%[7]

Source: Talbot Dir. Test. at 4-5.

3. Mr. Kivela's Analysis

Commission Staff witness Kivela's recommended ROE of 12.75% is based primarily on his DCF peer group analyses; he used his CAPM results as a "check" on his DCF analysis. Mr. Kivela developed a peer group with eight companies, which he then used in his DCF and CAPM analyses. Based on his various methodologies, which are summarized on Tables 3 and 4, Mr. Kivela developed an ROE range of 11.35% to 13.74%, with a midpoint of 12.54%. Mr. Kivela then adjusted the lower end of this range to 11.65%, which was his recommended ROE in Phase II of the BHE Alternative Marketing Plan (AMP) case (Docket No. 94-125). Thus, his adjusted ROE range is 11.65% to 13.74%, with a midpoint of 12.69%, which Mr. Kivela then rounded to 12.75% to develop his overall ROE recommendation.

[7] This number was then rounded to produce Mr. Talbot's recommended ROE of 11.80%.

Table 3: Summary of Mr. Kivela's DCF Analysis

	Low Estimate	Midpoint Estimate	High Estimate
Annual DCF Results	10.04%	11.10%	12.16%
Flotation Cost Adjustment	00.25%	00.25%	00.25%
All-In Annual DCF Results	10.29%	11.35%	12.41%
Quarterly DCF Results	10.23%	11.35%	12.48%
Flotation Cost Adjustment	00.25%	00.25%	00.25%
All-In Quarterly DCF Results	10.48%	11.60%	12.73%

Source: Kivela Exhibit RKSUR-1.

Mr. Kivela's overall cost of equity recommendation of 12.75% is about equal to Mr. Kivela's "high end" quarterly DCF estimate. Mr. Kivela believes that his use of the high end of his peer group DCF range is appropriate because, although the companies in his peer group were statistically similar to BHE, these companies exhibited a somewhat lower total risk profile than BHE.

Table 4: Summary of Mr. Kivela's CAPM Analysis

	Low Estimate	Midpoint Estimate	High Estimate
Current CAPM Results	11.78%	12.79%	13.79%
Historical CAPM Results	11.41%	12.29%	13.18%
Midpoint CAPM Results	11.60%	12.54%	13.49%
Flotation Cost Adjustment	00.25%	00.25%	00.25%
All-In CAPM Results	11.85%	12.79%	13.74%

Source: Kivela Exhibit RKSUR 1.

Mr. Kivela used the results of his CAPM analyses as a "check" on the reasonableness of his DCF results. Mr. Kivela also compared his "all-in" cost of equity recommendation of 12.75% with the allowed returns authorized in other jurisdictions.

4. Comparable Sample Analysis

a. Evidence

Company witness Strong developed a six-company peer group sample, which he then reduced to a two-company sample. The two companies that Dr. Strong believes are most comparable to BHE include Central Maine Power Company (CMP) and Northeast Utilities (NU).

Dr. Strong began by considering the 35 electric utilities that are included in the Electric Utility (East) industry covered by the Value Line Investment Survey. He then performed a "cluster analysis" using five variables: (1) 3-year average of cash flow per share to average share price; (2) 3-year average equity ratio; (3) 3-year average earned ROE; (4) 3-year average price/earnings ratio; and (5) 3-year average dividend yield. Dr. Strong found that BHE possesses a "nearly unique set of these financial characteristics" and that BHE is "more similar to CTP [CMP] and NU than to the other four firms in the sample."

Public Advocate witness Talbot states that Dr. Strong has used a number of "ad hoc procedures" that have limited reliability. Mr. Talbot states that Dr. Strong's heavy reliance on DCF analysis of Central Maine Power Company and Northeast Utilities can produce unreliable results because of the lack of statistical reliability and the danger of making ad hoc adjustments. Talbot notes that Northeast Utilities has now eliminated its dividend.

Staff witness Kivela raised two concerns about Dr. Strong's comparable sample. First, Mr. Kivela was concerned about the small size of Dr. Strong's peer group. Second, Mr. Kivela believes that Dr. Strong should not have used Northeast Utilities, which has eliminated its dividend, in his peer group. Dr. Strong's "spot" dividend yield measurement for NU was taken on April 11, which was after NU had suspended its dividend (on March 25, 1997).

Public Advocate witness Talbot applied his DCF method to two groups of companies, a group of four "more-comparable" companies and a group of six "less-comparable" companies. Mr. Talbot began by considering the 90 electric utilities that are included in the Electric Utility (East) industry covered by the Value Line Investment Survey. Mr. Talbot's selection criteria included: (1) the utility's 1996 common equity ratio must be at or below 40%; (2) the beta of the utility's stock must be at least 0.70; and (3) the utility's Value Line safety ranking must be below average. The four utilities that meet all three of these criteria are included in Mr. Talbot's "more-comparable" sample. The six companies that meet two out of three of Mr. Talbot's criteria are included in his "less- comparable" sample. Mr. Talbot stated that the companies in his "more-comparable" group are not as risky as BHE, which prompted him to develop his "extrapolation" approach.

Company witness Strong disputes Mr. Talbot's classification of companies as "more-comparable" and "less-comparable." Dr. Strong argues that a more reasonable segmentation of his ten-company peer group would be to classify CMS Energy, United Illuminating, and Eastern Utilities as more comparable, and the remaining seven as less comparable, which would result in an all-in ROE of 14.13% if Mr. Talbot's extrapolation methodology is used with these revised peer groups.

In determining his cost of equity recommendation, Staff witness Kivela relied primarily on the DCF model, which he applied to a sample of companies that have a somewhat lower total risk profile than BHE. Kivela Dir. Test. at 16. Mr. Kivela used six risk measures (developed using historical data for 1994-1996) in his peer group analysis, which included measures of business and financial risk. Mr. Kivela measures of risk include: (1) 3-year average cash flow to capital expenditures ratio; (2) 3-year average interest coverage ratio; (3) 3- year average common equity ratio; (4) 3-year average residential revenues to total electric revenues ratio; (5) 3-year average electric revenues to total revenues ratio; and (6) 3-year average operating income ratio. Mr. Kivela used a "cluster analysis to identify the 12 companies (out of a data base of 92 companies) that he believed were most comparable to BHE.

Mr. Kivela then removed four companies from that sample because these companies were involved in merger activities (Atlantic Energy Corporation and Allegheny Power System) or they are not currently paying a dividend (Niagara Mohawk Power Company and Northeast Utilities). Mr. Kivela found that BHE's overall risk profile ranked "among the highest (or most risky)" compared to his peer group sample.

Company witness Strong disputes Mr. Kivela's use of his peer group sample by arguing that BHE is riskier than Mr. Kivela's sample and argues that Mr. Kivela's error is that he fails to consider the combined impact of the six factors he identifies. Dr. Strong also argues that BHE's current BB- bond rating for its senior debt, as communicated in a private letter ruling by Standard & Poor's, suggests that BHE is riskier than Mr. Kivela's sample. The utilities in Mr. Kivela's sample have better bond ratings than BHE and only one utility in the sample has a bond rating that is below investment grade.

b. Analysis

We will begin our analysis of the various witnesses' peer group samples by stating our overall perspective on the use of peer groups in a cost of capital analysis. We believe that peer group analysis performs a very important role in a cost of capital analysis, especially when -- as here -- the DCF model and CAPM cannot be directly applied to the subject utility. In this case, peer group samples perform a particularly important role for two reasons. First, BHE has eliminated its common dividend and therefore the standard DCF model cannot be applied directly to the Company. Second, reliable estimates of beta are difficult to develop for BHE because few financial analysts follow BHE (e.g., BHE is not even followed by Value Line, which follows about 1,700 companies) and if we were to calculate BHE's beta based on historical data we would calculate a negative beta (because BHE's stock price has gone down in recent years while the "market" has gone up), which is a counterintuitive result.

As a general principle, we believe that a peer group should include enough companies to ensure that the results of the cost of capital analysis are not unduly influenced by any one "outlier" but should not be so large as to dilute comparability in risk to the subject utility. While the number of companies will vary based on the industry and the facts of a particular case, as a general matter an appropriate sample would likely include 5-12 peer group companies.

There are a number of ways to select a peer group sample. As a general matter, we believe that an appropriate selection process should consider a large number of potential candidates for the peer group sample and then should select the sample based on systematic and objective criteria that properly identifies companies that are most comparable to the subject company in terms of risk (and therefore in terms of required return).

Dr. Strong began his analysis by considering market-traded electric utilities in the eastern region of the U.S. that are followed by Value Line. In doing so, he failed to consider more than 55 utilities in the U.S., some of whom may be more comparable to BHE in terms of risk than the companies that he identified. After identifying a six-company sample and performing a DCF analysis, Dr. Strong chose to focus on two companies in his sample, Northeast Utilities (NU) and Central Maine Power Company. Dr. Strong chose to focus on Northeast Utilities when he performed his cost of capital analysis even though NU had eliminated its dividend several weeks previously (March 25, 1997); on cross-examination he agreed that the use of NU would present problems. Because NU has eliminated its dividend, we believe that Dr. Strong's DCF results for NU are not useful. That brings us to CMP: we agree that CMP is likely to be comparable to BHE in many respects but we are reluctant to give too much weight to the results of any one utility. We will give little weight to Dr. Strong's comparable sample companies as we consider the appropriate cost of capital for BHE further below.

Mr. Talbot began with a large group of companies, and used appropriate measures of risk to select a peer group sample. Because only four companies passed his "risk screens," Mr. Talbot developed an additional group of 6 companies that passed two out of three of his risk screens. Our primary concern with Mr. Talbot's methodology is the subjectivity involved in developing more "more-comparable" and "less-comparable" samples.

We appreciate that a considerable amount of judgment is involved is required to develop a "comparable sample," especially when, as here, all of the cost of capital witnesses acknowledge that BHE is riskier than its peer group sample. We are reluctant, however, to compound the judgment required by developing two peer group samples, followed by a judgment about the appropriate risk premium between the less-comparable and the more-comparable samples, and then an additional judgment about the appropriate risk premium between the "more-comparable" sample and BHE. We are reluctant to give very much weight to this approach because this methodology is overly vulnerable to arguments that companies should be shifted between the more-comparable and less-comparable group, which would result in an increase or decrease to Mr. Talbot's recommendation of 11.80%.

Staff witness Kivela's sample of BHE's peers provides a sound basis for identifying BHE's cost of equity. We recognize that the use of historical financial and operating ratios for a 3-year period (1994-1996) is an imperfect methodology for identifying companies that are comparable in risk to BHE at the present time. Because BHE's business and financial risk is affected by a number of unique factors, such as the sizable Ultrapower buyout, Maine Yankee's operating problems (which led to its recent closure), its limited financial flexibility in recent months, and other factors, the selection of a sample of peer group companies will necessarily be difficult and will require the exercise of sound judgment.

Given the limitations and uncertainties of forecast data and the possibility that financial and operating ratios for a shorter time period may reflect short-term aberrations rather than fundamental changes in business and financial risk, we believe that the 3-year period used by Mr. Kivela properly balances these considerations. We also believe that the risk measures Mr. Kivela uses were appropriate and that Mr. Kivela's "cluster analysis" methodology is appropriate.

We note that while Mr. Kivela did not explicitly include bond rating as a risk measure in his cluster analysis, the measures of business and financial risk that he used include financial and operating ratios that are commonly used by credit analysts (e.g., common equity ratio and cash flow/capital expenditures ratio). The fact that all but one of the peer companies have a bond rating of BBB- or lower suggests to us that Mr. Kivela's peer companies have lower levels of business and financial risk than BHE; Mr. Kivela has acknowledged that BHE is riskier than his peer group sample. We will consider BHE's relative riskiness further when we determine our estimate of BHE's cost of equity capital below.

We are somewhat concerned about the inclusion of Central & South West Corporation in Staff witness Kivela's peer group. Central & South West is rated A- by Standard and Poor's, while the other companies have a bond rating below BBB+. This company's A- bond rating suggests a perceived lower level of business and financial risk by S&P; if the market also perceives that Central & South West has lower risk, the inclusion of this company in the peer group could provide a downward bias to Mr. Kivela's cost of equity data.

More generally, we note that Mr. Kivela dropped two companies from his peer sample because they had announced mergers. We note further that Central & South West has recently announced its intent to merge with American Electric Power Company; while this announcement was made after the record in this case closed, it is conceivable that Central & South West's stock price was higher than it otherwise would have been when Mr. Kivela performed his cost of equity analysis because of its potential value as a merger candidate, which would be an additional source of downward bias in a DCF analysis. Because the issues concerning the inclusion of Central South West are quite speculative, we will not delete Central & South West from Mr. Kivela's sample.

5. Discounted Cash Flow Model

a. Evidence

Company witness Strong used the standard form of the DCF model with an average stock price (the average of the high and low prices occurring anytime during the year), and a growth rate that was calculated using the "b times r" method using five-year average retention ratio (i.e., 1 less the payout ratio) and five-year average earned ROE to develop an estimated sustainable dividend growth rate.[8] In addition, Dr. Strong calculated DCF results for two of his peer group companies, NU and CMP, using current (as of April 11, 1997) stock prices.

Public Advocate witness Talbot used the standard DCF model with two sets of inputs to develop his DCF results. The first set of inputs use the current dividend yield (using spot stock prices) and the lower of the mean and median long-term earnings forecasts reported by Institutional Brokers Estimate System (I/B/E/S). The second set of inputs use a historical dividend yield (using the average of the highest and lowest stock prices over the past 12-month period) and the higher of the mean and median long-term forecasts reported by I/B/E/S.

Staff witness Kivela relied primarily on a DCF analysis of the cost of common equity of his peer group sample to estimate the cost of equity of BHE. Mr. Kivela testified that the quarterly "core" DCF cost of common equity of his peer group ranges from about 9.75% to about 12.48%, with a midpoint cost of common equity of 11.11%. Using an annual DCF model, the peer group's DCF cost of equity ranges from 9.60% to 12.16%, with a midpoint of 10.88%.

No party disputed either the specification of Mr. Kivela's annual and quarterly DCF models or the inputs into those models. As explained by Mr. Kivela, the DCF model requires a current share price, a current dividend, and an expected growth rate. For his peer group sample, Mr. Kivela used a 20-day average of recent stock prices (June 26, 1997 to July 24, 1997), the current indicated dividend (from the S&P *Stock Guide*) and the five-year earnings growth rate (as found in the July 17, 1997 edition of the I/B/E/S Report and the July 1997 S&P *Earnings Guide*).

b. Analysis

We find that Mr. Kivela DCF analysis provides a sound basis for determining BHE's cost of common equity. We

[8] A 10-year average retention ratio and earned ROE were used for CMP.

will rely primarily on the results of Mr. Kivela's DCF analysis in determining the cost of equity below. We will give little weight to Dr. Strong's DCF analysis because of our concerns about Dr. Strong peer group, which we discussed previously. We also note that we generally prefer to use a forward-looking growth rate in a DCF analysis rather than using historical growth rates as a proxy for the forward-looking growth rate because the electric utility industry is rapidly changing from a comprehensively regulated industry to a more competitive industry structure. As a result, historical growth rates may not be indicative of future growth rate performance. This is an additional reason to give little weight to Dr. Strong's DCF results.

While Mr. Talbot's DCF model and his inputs into that model are generally reasonable, we will not give significant weight to his model because of our concerns about his two peer group samples and his "extrapolation" method, which he used to determine the appropriate cost of equity for BHE.

The DCF model (and the inputs into that model) used by Mr. Kivela are familiar to us. Because we have relied on similar approaches in the past, and because the methodology and inputs Mr. Kivela developed are largely undisputed, we find little reason to extensively analyze Mr. Kivela's DCF analysis in this order. We will continue to rely most heavily on the DCF model in determining the appropriate cost of common equity for BHE.

We agree with the cost of capital witnesses in this proceeding that BHE is riskier than the various peer group samples and therefore has a higher required ROE. We will evaluate this issue when we determine BHE's cost of common equity below.

6. <u>Capital Asset Pricing Model and Other Models</u>

a. <u>Evidence</u>

Dr. Strong relied primarily (80 percent) on the results of his CAPM (40 percent) and historical risk premium (40 percent) methods in developing his cost of equity recommendation for BHE. To develop his CAPM recommendation of 11.92%, Dr. Strong used a beta of 0.80, a "risk-free" rate of 5.2% based on U.S. Treasury Bills, and an equity/debt "risk premium" of 8.4%. Mr. Kivela disagrees with Dr. Strong's assertion that it is more appropriate to use U.S. Treasury bills in a CAPM analysis because of the "reinvestment risk" associated with short-term securities.

To develop his historical risk premium method of 13.25%, Dr. Strong used a bond yield of 9.50% for BHE and then argues that BHE's equity should have a premium of 3.75% over that bond yield. Dr. Strong argues that for a typical electric utility with a beta of about 0.7, the risk premium has been shown to be about 3.00% to 4.00%. Mr. Talbot criticizes Dr. Strong's selection of 13.25% rather than a range of 12.50% to 13.50%; Mr. Talbot argues that Dr. Strong has overestimated BHE's historical risk premium by going to the higher end of that range.[9] Mr. Kivela recommended that the Commission give little weight to Dr. Strong's historical risk premium method because the size of the equity risk premium varies over time with the relative level of interest rates and other factors and therefore it is difficult to apply the historical risk premium approach in current periods. Mr. Kivela also argued that Dr. Strong should have estimated an equity risk premium over U.S. Treasury securities rather than BHE's corporate bonds.

Mr. Talbot performed a CAPM analysis as a "check" on his DCF results and relied on both methods in developing his cost of equity recommendations. Mr. Talbot used a beta estimate of 0.73 based on Value Line data for his two peer group samples; "risk-free" rates of 5.13% and 6.47% for U.S. Treasury bill and bond rates, respectively, as reported in the New York Times on August 6, 1997; and an equity/debt "risk premium" of 8.9% and 7.3% for Treasury bill and bond rates, respectively, using estimates of long-term historical risk premiums reported by Ibbotson Associates for large-company stocks. Based on these inputs, Mr. Talbot developed an estimate of 11.63% using Treasury Bills and 11.80% using Treasury Bonds, which produced an average CAPM estimate of 11.71%.

Mr. Kivela uses the CAPM as a "check" on his DCF models. Mr. Kivela found that the CAPM "core" cost of equity of his peer group sample ranges from 11.60% to about 13.49%, with a midpoint of 12.54%. Inputs into the CAPM include:

(1) Estimate of the risk free rate. Mr. Kivela used two estimates. First, he used the 5.21% yield on three-month U.S. Treasury Bills. Second, he used the 6.52% yield on 30-year Treasury Bonds.

(2) Estimate of the return on the market portfolio. Mr. Kivela used two approaches to estimate the return on the market portfolio. First, Mr. Kivela conducted a DCF analysis on the firms in the S&P 500 Stock Index. The weighted-average DCF cost of equity of the 424 firms that had

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[9] Mr. Talbot's numbers were adjusted to reflect the changes Dr. Strong made to his historical risk premium recommendation during the rebuttal phase of the case.

adequate data available was 14.60%. Second, Mr. Kivela used the same historical data, collected by Ibbottson Associates, as Mr. Talbot.[10]

(3) Estimate of the firm's systematic risk or beta. Mr. Kivela used beta estimates, as published by Value Line, for the firms in his peer group. The published beta estimates ranged from 0.70 to 0.90, with a midpoint of 0.80.

Dr. Strong argues that, theoretically, the only relevant beta is a forward-looking beta estimate and that the statistical significance of the beta estimates is important. Strong Reb. Test. at 2-3. The Public Advocate disputes Mr. Kivela's inclusion of Unicom in his peer group sample.

b. Analysis

We find that the CAPM results provide a useful check on the DCF analysis. The theoretical weaknesses of the CAPM, however, cause us to rely more heavily on the DCF analysis in our decision making. CAPM is familiar to us and thus we need not discuss the basic structure of the model in this order.

We will not rely on Dr. Strong's CAPM analysis. While we are satisfied that Dr. Strong's 0.80 beta estimate is reasonable, we will not rely on Dr. Strong's estimates of the risk-free rate and the appropriate risk premium. With respect to the risk-free rate we are concerned that U.S. Treasury Bills have a duration that is much shorter than that of equity securities and therefore may not be an appropriate proxy for the risk-free rate in a CAPM analysis; we prefer to use both U.S. Treasury Bills and Bonds when we consider the appropriate risk-free rate. With respect to the appropriate risk premium, we are concerned with Dr. Strong's use of only historical risk premium data. The heavy reliance on historical risk premium data is also our primary concern with Mr. Talbot's analysis.

We will give no weight to Dr. Strong's risk premium analysis because we are concerned about the subjectivity inherent to developing his 3.75% risk premium. This premium was based on a 3% to 4% "rule of thumb." We believe that equity risk premiums vary over time depending on interest rates and economic conditions and Dr. Strong failed to give us more than a very general analysis of the cost of equity for BHE based on the equity risk premium method.

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[10]There are small differences between Mr. Talbot's and Mr. Kivela's Ibbottson estimates, which appear to be due to differences in rounding.

We will use Mr. Kivela's CAPM model and his inputs into that model as a check on the DCF model. We will adopt Mr. Kivela's 0.8 beta, which is based on 5 years of historical data as reported by Value Line. That period is long enough to smooth out short-term aberrations while also being short enough to be reasonably reflective of future conditions. While a more forward looking beta estimate would be desirable from a theoretical perspective, we recognize that it is difficult to develop one in practice.

We will adopt Mr. Kivela's risk-free rates based on U.S. Treasury Bills and Bonds; by using an estimate with a very short duration and an estimate with a very long duration, we can get a better sense of the appropriate risk-free rate in a CAPM analysis.

We find that Mr. Kivela's historical risk premium data and a forward-looking estimate of the risk premium (using a DCF of the S&P 500) is appropriate. Because we generally prefer to use forward-looking estimates where possible, we will rely more heavily on Mr. Kivela's 12.79% CAPM result, using a "current" risk premium.. We will give less weight to Mr. Kivela's "historical" CAPM results.

7. Issuance Costs

a. Evidence

Dr. Strong recommends a 43 basis point adjustment to the "core" cost of equity to reflect flotation costs Mr. Kivela believes that Dr. Strong's 43 basis point (5.0%) recommendation is outdated and is also too large. Mr. Talbot also relied on outdated estimates of flotation costs.

Staff witness Kivela recommends a 3.70% adjustment for issuance expenses, which amounts to a 25 basis point upward adjustment to his core ROE range of 11.40% to 13.49%, with a midpoint of about 12.75%. Mr. Kivela's "all-in" cost of equity recommendation is 12.75%, which is the midpoint of a range of 11.65% to 13.74%.

Mr. Kivela's 3.70% issuance costs recommendation is based on Mr. Kivela's review of recent issuance costs for eight electric utilities. With data for these eight electric utilities, Mr. Kivela developed a range of 2.74% to 3.69%, with a midpoint of 3.22%. Mr. Kivela rounded the upper end of that range to 3.70% and then relied upon the higher end of the range for his issuance costs recommendation. Mr. Kivela recognized that BHE's issuance costs would likely be higher than his "issuance cost" peer sample because BHE's equity issuances would be smaller than the peer sample and some issuance expenses are fixed. Then he used a formula to calculate a 25 basis point issuance expense "adder," assuming a cost of equity of 12.75%.

b. Analysis

Issuance (or flotation) costs are the costs that are associated with raising equity capital. We continue to believe that reasonable issuance costs should be recovered from ratepayers. Mr. Kivela's 3.70% issuance cost estimate (or 25 basis points) was based on a sample of five electric utilities that raised new common equity between May 1994 and November 1996. We will adopt Mr. Kivela's 3.70% issuance cost estimate because we continue to believe that issuance costs should be recovered from ratepayers and because this is the most timely and useful estimate that is before us.

8. The Cost of Equity Capital for BHE

All three of the cost of capital witnesses in this proceeding agree that BHE is one of the most risky electric utilities in the U.S. at the present time, but they disagree about the appropriate cost of equity for the Company. The cost of equity estimates range from 11.80% (Public Advocate) to 13.62% (Company). Mr. Kivela developed a cost of equity range including issuance costs) of 11.65% to 13.74%, with a recommended midpoint of 12.75%.

We believe, generally, that BHE's cost of common equity is within Mr. Kivela's range. We will adopt Mr. Kivela's recommended midpoint of 12.75% because it is based on appropriate cost of capital methodologies and properly reflects BHE's risk. As discussed in earlier sections of this Order, we are generally comfortable with Mr. Kivela's methodology and inputs used in developing his DCF and CAPM cost of equity estimates. We agree with Mr. Kivela that the DCF peer group should be relied upon most heavily in forming a judgment on the cost of equity.

We believe that BHE is riskier than Mr. Kivela's peer group but we believe this increased risk is appropriately addressed by using a 12.75% cost of equity (including issuance costs), which is consistent with the higher end of Mr. Kivela's DCF results and is also consistent with the midpoint of his CAPM results (using a forward-looking estimate of the return on the market portfolio).

BHE has operated in a difficult risk environment for a number of years. Relevant risk factors include: (1) a relatively weak economy in its service territory; (2) substantial purchased power commitments (albeit moderated by the recent buyout of its Ultrapower contract, which, however, has increased its financial leverage significantly); (3) increasing power costs as a result of the recent closure of Maine Yankee; and (4) its elimination of its common dividend. At the present time, BHE has a high degree of financial leverage (as evidenced by an common equity ratio of about 27%) and very little financial flexibility, which severely limits BHE's ability to raise additional debt or equity capital at a reasonable cost.

It might be possible to argue that we should go to the higher end of Mr. Kivela's cost of equity range to adequately reflect the risks that we recognize that BHE is facing. We believe, however, that we have adequately recognized these risks by adopting Mr. Kivela's 12.75% cost of common equity. In addition, we recognize the heavy burden that the Company's rate increase will impose on residential, commercial and industrial customers in BHE's service area. This is an additional reason to adopt a 12.75% "all-in" cost of common equity to be used in calculating the allowed overall rate of return for the Company.

Based upon our consideration of the evidence on the cost of equity we will adopt a cost of equity, including issuance costs, of 12.75%. We find Mr. Kivela's analysis to be very helpful in making this decision. As discussed earlier, we are comfortable with Mr. Kivela's methodology and inputs used in developing his DCF and CAPM cost of equity estimates. We agree with Mr. Kivela that the DCF peer group should be relied upon most heavily in forming a judgment on the cost of equity.

D. Overall Cost of Capital

The cost of capital is established by deciding the appropriate proportion of each component of the capital structure and by determining an appropriate cost rate for each of the component parts. The weighted average sum of the components equals the overall cost of capital.

With one exception, the Advocacy Staff has agreed to use the capital structure proposed by the Company. The proposed capital structure is an average capital structure for the rate effective year. Witnesses for the Company and the Staff agree that Exhibit PR-1-1 should be corrected to reflect a cost of UltraPower debt of 9.13%.

The Company and Staff disagree on how the Company's potential transaction with Penobscot Energy Recovery Company (PERC) should be financed. The Company anticipates issuing debt with a cost rate of 11.35% as part of the PERC transaction. The Staff argues that that financing cost is unreasonable and that they should rely on the $6.00 million BankBoston PERC "bridge financing, which would be available if they close the financing transaction that uses the Company's power sales contract with UNITIL as collateral for a long-term loan (Docket No. 97-839).

The Company argues that the Company will have extremely tight cash flows during the summer of 1998 and that the Company's best available opportunity to alleviate its cash flow difficulties is to complete the permanent $6.00 million financing. We agree. While 11.35% is a high cost of debt, and we expect the Company to minimize its cost of debt, we believe that this is a reasonable rate to pay for unsecured (e.g., "junk bond") debt and we have incorporated a $6.00 million bond issue at 11.35% on Table 4 below.

Table 4: Overall Cost of Capital

	% of Total Capital	Cost	Weighted Average Cost of Capital
Long-Term Debt	33.19%	9.13%	3.03%
Ultrapower LTD	35.50%	7.96%	2.83%
Total LTD	68.69%	-	5.86%
Short-Term Debt	0.98%	8.51%	0.08%
Preferred Equity	3.61	8.18	0.30%
Common Equity	26.72	12.75	3.41%
Total Capital	100.00%	-	9.65%

As shown on Table 4, we find that BHE has an overall cost of capital, or weighted average cost of capital, of 9.65%, using the average capital structure, the embedded cost rates shown on Table 4, and an "all-in" cost of common equity of 12.75%. We adopt this 9.65% overall cost of BHE's capital as the allowed overall rate of return on capital, which we will use in calculating BHE's revenue requirement.

VI. SPECIAL ADJUSTMENTS

A. The "Revenue Delta" Adjustment

Because we did not adopt a formal rate plan in conjunction with BHE's pricing flexibility plan, we must decide whether customers who do not receive discounts should make up in entirety the revenue lost because BHE has granted rate discounts to other customers.

1. Advocacy Staff Position

The Advocacy Staff asserts that core customers, or customers who do not receive discounted rates or contracts, should not make up for all the “revenue delta.” The “revenue delta” refers to the difference in revenue actually received under discount rates compared to the revenue that would have been received if the electricity had been purchased at the regular retail rate. Because there are some risks that discounts could be granted when none were needed and that some discounts may have been greater than necessary, and because prudence reviews of the discount decisions are now impracticable, the Advocacy Staff argues that principles of equity call for sharing the revenue loss between ratepayers and shareholders. A 50/50 sharing ratio was chosen because of the inherent equity of equal sharing and the lack of a better alternative.

2. Bangor Hydro Position

The Company responds that sharing is not proper. In the Company’s view, the Commission should not treat discounted contracts differently from other expenses incurred by a utility, that is, action by the utility is presumed to be prudent until some evidence of imprudence puts on the Company the burden of proving the prudence of the expense. As to the discounted rates and contracts, the Company argues that there is no evidence of any imprudence, and it would be unfair to charge shareholders the lost revenue between the tariffed rate and the discounted rate or contract. Because it would be imprudent to not selectively discount rates, BHE views the Staff's sharing proposal as a poor substitute for prudence reviews of the discount decisions.

In addition to constituting poor regulatory policy, sharing is unfair in BHE’s view. In testimony, Carroll Lee of BHE stated that the risk that a discount was given unnecessarily is minimal. The only significant risk was that a discount might be slightly larger than necessary. In Mr. Lee’s view then, a 50/50 sharing of the revenue delta was out of line with the risks actually facing ratepayers by BHE’s action.

3. Decision

The regulatory flexibility granted BHE by adoption of the AMP was not “traditional.” Prior to the AMP, special contracts required specific Commission approval pursuant to section 703. A discounted tariff or rate schedule likely would have been suspended and investigated for 8 months beyond its 30-day effective date. A special contract for a discounted rate would have been approved only upon a Commission determination that the customer would not have remained a customer at the customer's tariffed rate and the discount agreed to with the utility was not larger than necessary to keep the customer. Such proceedings must essentially subject the customer to a level of investigation similar to that of a regulated utility. *See Bangor Hydro-Elecric (Proposed Contract with Lincoln Pulp and Paper*) Docket No. 89-411 (October 16, 1990); Central Maine Power (*Investigation of Special Rate between CMP and AIRCO Industrial Gases*), Docket No. 92-331 (September 22, 1993).

As competitive alternatives to electricity became viable for many customers, the Legislature passed section 3195(6), which allows the Commission to authorize pricing flexibility programs whereby the utility can discount rates with limited or no Commission approval. In the *AMP II Order*, we recognized that an incentive mechanism would insulate ratepayers from the risks associated with rate discounts and would pass the risk to the utility. Future rate increases are tied to the inflation-based formula, regardless of whether discounts are granted, and if granted, whether they are proper. We accepted the "informal" stay out proposal as an alternative incentive mechanism.

The failure of the stayout proposal to avoid a traditional rate case means that the informal stayout did not work to avoid the risks associated with flexible pricing. In the absence of an after-the-fact substitution of a "formal" rate mechanism, discussed in the next sub-section, two options remain: a ratemaking adjustment can be made to share the risk associated with such pricing flexibility; or a prudence investigation can be conducted to determine whether any harm resulted from improper flexible pricing.

BHE argues that core customers must pay for the "revenue delta" absent a finding of imprudence on BHE's part in engaging in flexible pricing. We agree with BHE that there is no evidence of imprudence by BHE in granting any rate discounts. No party conducted a prudence investigation. Neither did the Commission direct or ask that one be conducted. In fact, we stated a reluctance to rely on after-the-fact prudence investigations in assessing the reasonableness of pricing flexibility actions in the *AMP I Order*. Any prudence review of utility action is expensive and contentious. In a pricing flexibility prudence investigation, we also have to assess the actions of and alternatives available to the customer receiving the discount. We remain convinced that pricing flexibility decisions should not be treated like ordinary utility expenditures in which prudence investigations provide the assurance that utility actions have been reasonable. The best means to protect ratemakers from unreasonable price discounts is to adopt an incentive mechanism like a price cap in which future rate increases are unrelated to the amount of discounts granted. It is simply too difficult and expensive to realistically review the utility's actions and customer's alternatives that resulted in the utility granting a price discount.

Because we will not rely on prudence reviews of BHE's pricing flexibility decisions, we hold that the Company should bear some of the costs associated with the pricing flexibility discounts. Regulatory precedent supports ratemaking adjustments whereby costs of the "not-reasonably-reviewable" utility action are shared between ratepayers and shareholders. In *Maine Public Service Company*, 67 PUR 4th 101, 115 (Me PUC 1985), the Commission rejected the 50/50 sharing of canceled plant expenses for Seabrook 2 because a detailed prudence investigation had been conducted by the Commission. The Commission distinguished earlier cases involving investment in the cancelled Sears Island, Montague and NEPCO nuclear plants because the investment in those plants was not significant enough to warrant the detailed planning and nuclear engineering review that the Commission conducted for Seabrook. In the absence of a comprehensive prudence review, the Commission found an approximate 50/50 sharing between ratepayers and shareholders to be reasonable, even though there was no evidence of imprudence of any of the investment. *Central Maine Power Company*, Docket No. 80-25 (1980) (Sears Island); *Central Maine Power Company*, Docket No. 81-127 (1982) (Montague); *Bangor Hydro Electric Company*, Docket No. 81-136 (1982) (NEPCO); *Maine Public Service Company*, Docket No. 80-180 (1981) (NEPCO).

In the context of pricing flexibility and BHE's financial condition, however, we reject a 50/50 sharing of costs between ratepayers and shareholders. We find credible Mr. Lee's argument that the risks associated with BHE's decisions to enter into rate discounts were significantly less than the risks that BHE negotiated a discount larger than necessary to retain a customer. As such, a 50/50 sharing would assign a disproportionate amount of the costs to shareholders.

In addition, our canceled plant decisions require us to assess the financial integrity of the utility before deciding to share costs between ratepayers and shareholders. The financial condition of BHE is of sufficient concern that we will choose a sharing ratio that allocates less to shareholders than we would if BHE's financial condition were more robust. However, financial forecasts demonstrate that BHE is sufficiently healthy to absorb some sharing of pricing flexibility costs.

Upon assessing the riskiness of unnecessary price discounts and the financial condition of BHE, we find a 85/15 ratepayer/shareholder ratio would fairly share the costs of the pricing discounts.

We will apply the 85/15 ratio to the "revenue delta" cost as calculated by Staff with one adjustment. Staff included in its calculation the revenue delta associated with the James River special contract. We believe that the revenue delta should not include the James River contract. The James River contract actually predates the AMP. The Commission approved the James River contract, leaving open the docket so that BHE could demonstrate the prudence of the contract (Docket No. 93-355). Although the investigation was never concluded, a Commission consultant did conduct a significant amount of analysis and his report did not identify any prudence issues. Staff witness Monroe testified that, given the review that took place, it would be reasonable to remove the contract from the revenue delta. We agree, and remove the James River contract from the revenue delta calculation. This apportionment results in $368,399 of the revenue delta being applied to the Company as a reduction to its allowed revenue increase.

B. Rate Design of the Revenue Delta

In addition to the 50/50 sharing of the revenue delta proposed by the Advocacy Staff, it also recommended that the amount of revenues over which the revenue requirement is spread be adjusted to theoretically split the difference between shareholders and ratepayers. Staff explains that the methodology propounded in its testimony does not accomplish an exact 50/50 split, but rather results in a slightly higher assignment of revenue responsibility to the Company. Nevertheless, Staff believes that its recommended method is a reasonable way to apportion the risk related to discount rates from core customers to the Company.

Staff excluded the revenues from special space heating rates, HoltraChem, Great Northern Paper and other utilities from the non-core revenue amount and revenue delta calculation. Exhibit AM-S2 of Staff witness Monroe indicates that Staff adds half of the remaining non-core revenues and half of the test year revenue delta to the test year core revenues to determine the denominator for calculating the percentage increase that is applied to core customer rates. Staff's recommended methodology results in a 6.22% increase for core customers.

Staff asserts that its methodology attempts to place the revenue responsibility of core ratepayers halfway between what their responsibility would be if the Company were to bear full responsibility for the discounts and what the responsibility would be if the Company bore no responsibility for the discounts. Staff admits, however, that its mathematical methodology does not exactly split the difference, and that a slightly revised formula might better capture what it is trying to accomplish. Staff argues that whatever formula is used, the revenue delta must be used both in calculating the revenue deficiency and in allocating the revenue deficiency, because to do otherwise would shift more than 50% of the risk to core ratepayers. Staff claims that its methodology does not result in a double counting of adjustments.

The Company counters that using the Staff's rate design recommendation would require that 50% of any rate increase that cannot be passed on to special rate customer is absorbed by the Company's shareholders, and that referring to such an adjustment as "rate design" is disingenuous. Rather, BHE claims that it is merely an attempt to pass some of the revenue deficiency on to the Company's shareholders, and it represents a type of double jeopardy, because it punishes shareholders for exactly the type of activity as does the revenue delta adjustment proposed by the Staff. The Company claims that Staff's proposal would result in BHE's absorbing about 30% of the revenue increase to which it otherwise would be entitled under the Staff's analysis. The Company asserts that the Staff proposal is arbitrary, unreasonable and unconstitutional.

The OPA does not support the Staff rate design recommendation, because he asserts that adoption of the Staff's rate design proposal could have a chilling effect on the future willingness of potential bypassers to enter into special rate contracts, because it could signal that customers with special rate contracts might be required to absorb a portion of any rate increase granted the Company. Also, the Commission gave preliminary consideration to this proposal in the BHE emergency rate case and rejected it. Finally, OPA states that record is not clear on the effect that the proposal would have on the Company and its customers.

We decline to adopt Staff's proposal in this proceeding. Given the Company's relatively precarious financial situation, we find that adoption of the Staff's rate design recommendation would require the Company and its shareholders to absorb a larger portion of the revenue deficiency than is justified under the circumstances. Moreover, we have already included a portion of the revenue delta in our revenue requirement calculation, and we find that is a sufficient sharing of the risk of special rate contracts between core customers and the Company.

C. <u>The OPA's After-The-Fact Rate Cap</u>

The OPA supports the primary recommendation by its witness Lee Smith that the Commission "reconsider" its *AMP Phase II* decision by granting an increase as if a CMP-type ARP was in place for BHE. In this way, the risks associated with AMP discounts would be shifted away from ratepayers. The ARP would permit an increase that is equal to one-half of the additional revenue needed to bring the Company up to the lower band of a return on equity that is 350 basis points below the ROE allowed in the last rate case, for BHE 10.56%. Ms. Smith calculates BHE's increase to be approximately $2.8 million.

BHE responds that the Commission does not have the authority to retroactively impose a rate cap plan. In addition to the statutory violation, BHE contends that its due process rights would be violated if the Commission were to adopt Ms. Smith's primary recommendation. In *AMP Phase II*, the Commission explicitly rejected adopting a formal incentive plan. BHE points out that no party even proposed a CMP-type rate cap in the AMP proceeding, and BHE asserts that it would be fundamentally unfair to impose a rate cap without notice.

In our *Order Approving § 312 Rates*, we found that there was no reasonable possibility that Lee Smith's primary recommendation would ultimately prevail in this case. For purposes of that finding, we did not even address BHE's statutory authority and Due Process arguments. Instead, we found that equity required that we examine the Company's financial results from the time when the rate cap would have been implemented, and provide for any intermediate adjustments to rates that might have occurred along the way. The AMP proceeding began about the time CMP's ARP investigation began, and CMP has had rate cap increases in 1995, 1996 and 1997. Ms. Smith assumes that the rate cap began with the test year used in the rate case (1996), but a rate cap plan would have been implemented sooner than that, and BHE may have been able to receive increases during the operation of the plan.

The OPA did not address our concern in its brief. We remain convinced that the correct calculation of a "remedy" to set rates now as if a rate cap had been adopted for BHE would require a rate increase significantly greater than $2.8 million. Accordingly, we reject Ms. Smith's primary recommendation.

VII. RATE PLAN AND RECONCILIATION MECHANISMS

A. Summary of the Positions of the Parties

The Staff supports an alternative rate plan for BHE as well as reconciliation of certain of its costs. The Company opposes a rate plan but supports reconciliation of a larger set of its costs than does Staff. The Public Advocate urges the Commission to adopt a price-cap plan for BHE, consistent with the testimony of Staff witness Reishus, and urges the Commission to allow BHE to recover Maine Yankee expenses through a reconciliation process.

B. Background on Rate Cap and Reconciliation Issues

We have considered alternative rate plans for BHE, as well as Central Maine Power Company and Maine Public Service Company, on several occasions in the past several years. In Docket No. 92-345(II), the Commission stated in its Order that utility price cap plans are likely to provide a number of potential benefits:

> (1) electricity prices continue to be regulated in a comprehensible and predictable way; (2) rate predictability and stability are more likely; (3) regulatory "administration" costs can be reduced, thereby allowing for the conduct of other important regulatory activities and for CMP to expend more time and resources in managing its operations; (4) risks can be shifted to shareholders and away from ratepayers (in a way that is manageable from the utility's financial perspective); and (5) because exceptional cost management can lead to enhanced profitability for shareholders, stronger incentives for cost minimization are created.

92-345(II) Order at 126.

For BHE, the Commission stated in 1994 that:

> [i]n our view, BHE's "good faith" offer to "freeze" rates for 5 years can provide for the eventual development of an acceptable broad- based incentive mechanism. . . . A stay-out plan could:
>
> Strengthen BHE's incentive to control costs and avoid losing revenues due to unnecessary rate discounts. While pricing flexibility is not singled out for special attention under this price cap proposal, BHE should clearly understand that lost revenues can have as much of an impact on its "bottom line" profitability as excessive costs.
>
> Shift the risk of poor financial performance away from ratepayers while allowing BHE a reasonable opportunity to improve its financial integrity.

> Provide BHE with a comprehensive incentive to bolster its revenues and profitability in a way that is comprehensible to the public.
>
> Provide an integrated solution to BHE's request for pricing flexibility in order to prevent or at least minimize unforeseen consequences resulting from the combined operation of the AMP. A price cap would assure that "captive" ratepayers do not subsidize rate reductions to customers with options to service from BHE.

The Commission went on in its Phase I Order to encourage parties to develop a price cap plan for BHE that reflected the benefits of incentive regulation. In *AMP (II)*, the Commission rejected the Staff's formal plan for the Company, noting that the benefits it cited in Phase I, listed above, could be achieved without a plan as "long as BHE keeps its promise to customers."

C. Rate Plan Issues

Based on the evidence that is before us, we believe that a price cap plan is needed to strengthen BHE's incentives to be efficient, to provide rate predictability and stability, and to reduce the administrative costs of regulating BHE. We find that the adoption of a price cap plan is necessary so that the risks associated with future rate discounts will not be borne by core customers to the same extent as they have with the informal "stayout rate plan." We desire to avoid facing a revenue delta adjustment issue again for BHE. Additionally, our incentive ratemaking statutory authority permits us to reconcile Maine Yankee-related costs. This authority is important to BHE because of the uncertainty and magnitude of these costs, and to ratepayers because any costs recovered now but later found imprudent may be returned to ratepayers. ***See*** 35-A M.R.S.A. § 3195.

The price-cap plan we adopt is flexible enough to be manageable for the Company from a financial perspective while also shifting some risks away from ratepayers. The price-cap plan that we adopt will extend through February 29, 2000, and will include: (1) a price index (chain-type GDP-PI); (2) a 1.2% productivity offset; (3) 50/50 profit sharing with a 350 basis point bandwidth on either side of the allowed ROE, based on its 1998 earned ROE for regulatory accounting purposes, and (4) provisions for exogenous costs, which will include certain "reconciliation costs" and other exogenous costs. There will be annual review proceedings in 1998 and 1999. The 1998 annual review proceeding will commence with a March 15, 1998 filing, which will only address an exogenous factor related to recovery in rates of the costs associated with ice storm of 1998 service restoration. The 1999 annual review proceeding will commence with a February 15, 1999 filing and will be completed by May 1, 1999, as described in more detail below.

1. Price Index

Staff supported the use of the chain-weighted GDP-PI. Staff witness Reishus noted that the chain-weighted GDP-PI eradicates the substitution bias that was present in the fixed-weight method previously reported by the federal government. Reishus Dir. Test. at 6. We will use the chain-weighted GDP-PI in BHE's ARP.

2. Productivity Offset

Staff supports the use of a 1.5% productivity offset, which comprises a 1.2% productivity estimate plus a 0.3% "stretch factor. The Company disputes the size of Staff's proposed productivity offset, believing that it is set too high and is arbitrary. Staff notes that the Company's total expenses/kWh stayed flat during 1992-1996 while inflation averaged about 3% per year during that time period. Thus, the Company's overall productivity during this period has been about 3% per year. During that same time period, the Company's average labor productivity has been about 7.3% and its expenditures per kWh has dropped by about 4.0% annually in actual dollars (not adjusted for inflation). Therefore, Staff argues that a 1.2% productivity offset is clearly achievable.

We will adopt a 1.2% productivity offset. We find that Staff's analysis would support the use of a considerably higher (2.5% to 3.7%) productivity offset but we find that the use of a 1.2% productivity offset will provide an adequate measure of productivity for BHE. We will not adopt Staff's proposed 0.3% "stretch factor" for BHE because the 1.2% productivity offset, in combination with BHE's currently constrained financial circumstances, should provide sufficient efficiency incentives for the Company.

3. <u>Exogenous Costs</u>

Staff supports allowing the Company to pass through certain exogenous costs. Staff witness Reishus recommends that "mandated costs" that are beyond the control of the Company's management, that are mandated by actions of the government or regulatory bodies, and that individually exceed $500,000 in annual revenue requirement, be included in the rate change as an adjustment to the index. In addition, as discussed below, Staff recommends that a Maine Yankee reconciliation mechanism be adopted.

BHE argues that Staff's requirement that any exogenous cost must individually exceed $500,000 is arbitrary and creates a downside risk for the Company. BHE also argues that the price cap plan and the reconciliation mechanism for Maine Yankee costs are not interconnected and recommends that the Commission analyzes the two issues separately. In the BHE ARP, exogenous costs (or Z factors) shall include True-Up Factors (or T factors) and Other Exogenous Changes (OEC). True-up factors will include certain costs associated with Maine Yankee. These true-up factors will be discussed further below.

Other exogenous factors shall include those extraordinary costs that: (1) exceed $300,000 in annual revenue requirements at the time of inclusion in rates for each item; (2) have a disproportionate effect on BHE or the electric power industry; and (3) would not be accounted for adequately through the index. Increases or decreases in these costs, when applicable, will be treated as part of the 1998 and 1999 annual reviews and price changes.

We will adopt a $300,000 minimum on recovery of individual exogenous costs rather than the $500,000 supported by Staff. If the individual exogenous cost exceeds $300,000, the full amount of the individual exogenous cost will be flexible for recovery at the time of the annual review. We believe that BHE's limited financial integrity does not allow BHE to accommodate greater increases in its exogenous costs.

The exogenous cost treatment that we have developed, including the reconciliation of Maine Yankee costs, is reasonable, allows BHE sufficient revenues to allow it the opportunity to earn its costs of capital and maintain and improve its financial integrity, and is likely to reduce the administrative cost of regulation. While it would be possible to reconcile Maine Yankee costs without developing an ARP for the Company, we believe that a holistic approach, which includes a price cap and reconciliation of certain Maine Yankee costs, will provide better incentives to the Company, reduce the administrative costs of regulation, and better provide rate predictability and stability.

4. Profit Sharing Issues

Staff supported the use 50/50 sharing and a bandwidth of 350 basis points on either side of the allowed ROE. Staff also stated that given BHE's recent financial difficulties, a smaller bandwidth, on the order of 225 basis points, would provide some additional shareholder protection while still fulfilling the incentive function offered by a bandwidth. The Company believes that 50/50 sharing may be unfair in certain circumstances and that the size of the bandwidth is arbitrary.

We will adopt a 350 basis point bandwidth for the Company. The Company will be eligible for risk sharing if the Company's annualized earnings for regulatory accounting purposes fall 350 basis points or more below the Company's allowed return on equity. Similarly, if BHE's earnings increase to 350 or more basis points above the target return on common equity, profit sharing could occur.

We adopt this approach because we believe that profit sharing, even if it occurs, is preferable to another comprehensive rate case. We are concerned that, given BHE's tenuous financial circumstances, there is a high degree of likelihood that the Company's earnings could be outside the "dead zone" and therefore "earnings sharing" could be triggered. If that were to occur, the administrative costs of regulation would not be lowered by the ARP and the Company's efficiency incentives could be distorted. However, on balance we believe that a "profit sharing" case with the issues limited based on our ARP for BHE is preferable to another comprehensive rate case for the Company. Thus, we will order 50/50 earnings sharing plan, with a 350 basis point bandwidth on either side of the allowed ROE of 12.75%, for the Company.

5. Annual Review Proceeding

BHE shall file information, as specified below, on March 15, 1998 and on February 15, 1999. The information will be used to compute the annual prices changes, which will go into effect on May 1, 1998 and 1999, which is the date that "summer" rates go into effect for those BHE customers that still have "seasonal" rates.

On March 15, 1998, BHE shall file information regarding the amounts that have been deferred pursuant to the Order in Docket No. 98-019 as well as a proposal regarding how these costs should be recovered. The Company should state whether it is reasonable to allow recovery of these costs over a 1-year period (May 1, 1998 to April 30, 1999) or, alternatively, whether a longer or shorter recovery period would be appropriate.

On March 15, 1999, the Company will file information, which will be used to compute the annual price changes and to ensure compliance with all aspects of the ARP. Information will include:

(1) Price index. The Company will provide the chain-weighted GDP-PI, as reported by the U.S. Department of Commerce, Bureau of Economic Analysis. The inflation rate will be calculated as the percentage change in the most recently available quarter of the prior year from the same quarter for the preceding year.

(2) Exogenous Costs. In the event that the Company is requesting exogenous cost recovery for any items, it will provide a calculation and supporting schedules showing that the impact of the specific item for which recovery is sought is greater than $300,000, and that the item could not be expected to be reasonably covered in the inflation index.

(3) Pricing flexibility. The Company will provide a schedule showing the various rates or special contracts that have been offered under the pricing flexibility provisions of the AMP, subject to applicable confidentiality provisions. BHE will also provide a calculation of the amount of sales and revenues under these special rates or contracts and an estimate of the total revenue that may have been achieved had no discount or special rates been provided.

(4) Profit Sharing. The Company will provide information on its earned ROE for regulatory accounting purposes for calendar-year 1998.

(5) Overall compliance. The Company will provide such additional information it believes necessary regarding its overall compliance with the ARP.

The Commission may modify the reporting requirements from time to time.

D. Reconciliation Issues

The Company has proposed that a reconciliation methodology be used for a list of nine items. These items include: (1) Maine Yankee FERC decommissioning case; (2) The dispute between Maine Yankee and the manufacturer of the defective fuel assemblies; (3) Litigation between the nuclear power industry and DOE over spent nuclear fuel; (4) NEPOOL’s proposed Regional Network Services (RNS) charge, which is pending at FERC; (5) NEPOOL’s proposed Outside Transaction Adjustment (OTA) charge; (6) Changes to NEPOOL’s capability responsibility rules; (7) NEPOOL's proposed "anti-hoarding" rules pending before FERC; (8) New England ISO charges; (9) The outcome of the PERC restructuring transaction. BHE argues that the Company has little, if any, ability to control the outcome of these items and that the Commission ought not to "gamble" that it can predict the outcome of each case accurately and set permanent rates accordingly. Instead, the Commission should provide for a "true-up" adjustment to more accurately reflect the cost of these items.

As part of its incentive plan, Staff supports reconciling certain Maine Yankee costs, including Maine Yankee O&M, property tax, and fuel costs based on actual expenses incurred during the test year. Staff notes that the Commission could also reconcile these and all other Maine Yankee costs, including replacement power costs, for imprudence should the FERC find that costs that have been allowed into rates as part of this case were in fact the result of imprudence. Staff also notes that mandated-type costs, such as NEPOOL tariff changes, that the Company might incur during the rate plan could be accommodated under the mandated cost provisions of the Staff's plan.

The Public Advocate supports Staff's rate plan, including Staff's recommendation to reconcile Maine Yankee expenses.

We will institute a reconciliation mechanism for the costs associated with BHE's share of Maine Yankee. Many of the future costs associated with Maine Yankee, including replacement power and decommissioning, are not sufficiently "known and measurable." Many costs may be substantial, so that misestimation may produce unacceptable earnings volatility for BHE, and perhaps, unreasonable rates for consumers. The deferral and reconciliation of Maine Yankee-related costs permits ratepayers to recover for any Maine Yankee costs now reflected in rates, but that are later found to be imprudent.

BHE is authorized to defer its incremental Maine Yankee costs in the appropriate deferred debit account. Incremental costs are those that exceed the amounts found reasonable for inclusion in the Company's revenue requirement in this Order, as measured beginning on December 12, 1997, the date that §312 rates became effective. Also as of December 12, 1997, all costs related to the Company's ownership of Maine Yankee, including replacement power, shall be subject to reconciliation and adjustment pending further regulatory findings at either the federal or state jurisdictional levels. The Company shall record carrying costs on the net deferred balance at the 9.65% cost of capital approved in this Order. Any accrued carrying costs must be separately identified until their ratemaking treatment is determined. The Company shall defer any tax effects associated with the deferral of Maine Yankee costs; these amounts should be separately identified in BHE's deferred tax accounts. Amounts deferred pursuant to this section shall be recoverable in rates as long as the amounts deferred were prudently incurred, were reasonably mitigated to reduce stranded costs, were found recoverable for wholesale ratepayers by FERC, and are calculated accurately in accordance with the provisions of this Order.

We will allow BHE to seek to recover as an Other Exogenous Cost (except for its congestion-related expenses, as discussed in Section IV F) its NEPOOL-related items to the extent that they exceed the $300,000 on an annual basis that we allow into BHE's test year revenue requirement. We will not allow BHE to reconcile or defer the costs associated with the PERC restructuring transaction, but given the size of the PERC restructuring costs, we confirm that the Company may file for exogenous cost treatment on February 15, 1999 if it is unsuccessful in completing the PERC restructuring transaction. We allow the possibility of adjustment at the Company's annual review if PERC-related costs will be significantly different in subsequent rate effective years. This item will be treated as a True-Up Factor and therefore the $300,000 minimum for an Other Exogenous Cost does not apply.

VIII. ORDERING PARAGRAPHS

Accordingly we

O R D E R

1. That the rate schedules filed by Bangor Hydro-Electric for effect on June 9, 1997 are unjust and unreasonable and are not allowed to take effect;

2. That Bangor Hydro Electric shall file substitute rate schedules that are designed to increase revenue by $13,222,365 over test year revenue, and by $8,123,804 over rates currently in place pursuant to 35-A M.R.S.A. §312, for effect no later than February 13, 1998;

3. That the rate design for the increased revenue be accomplished in the manner described in this order; and

4. That a price cap plan as described in the body of this Order is implemented for Bangor Hydro Electric.

Dated at Augusta, Maine this ____th day of March, 1998.

BY ORDER OF THE COMMISSION

____
Dennis L. Keschl
Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent
Hunt

This Document has been designated for publication.

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within 30 days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320 (1)-(4) and the Maine Rules of Civil Procedure, Rule 73 et seq.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320 (5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.

FRAMEWORK OF ALTERNATIVE RATE PLAN FOR BHE

	Issue	**Discussion**
1	Alternative Rate Plan (ARP) Required Through February 29, 2000	The ARP shall be a price-cap plan of the form Price Cap = (GDP-PI - Prod. Offset) +/- Z as described further below. The ARP shall take effect upon issuance of the Order in this proceeding.
2	GDP-PI	The index used for measuring inflation will be the chain-type Gross Domestic Product - Price Index (GDP-PI).
3	Productivity Offset	The productivity offset shall be 1.20%.
4	Exogenous Factors (Z)	Exogenous (or Z factors) shall include True-Up Factors (or T factors) and Other Exogenous Changes (OEC)
5	True-Up Factors (T)	True-up factors will include costs associated with Maine Yankee, including replacement power. The Company can also request to "true-up" costs associated with off-system capacity purchases, NEPOOL-related rates, and the PERC restructuring.
6	Other Exogenous Factors (OEF)	Other exogenous factors shall include those extraordinary costs that: (1) exceed $300,000 in annual revenue requirements at the time of inclusion in rates for each item; (2) have a disproportionate effect on BHE or the electric power industry; and (3) would not be accounted for adequately through the index. Increases or decreases in these costs, when applicable, will be treated as part of the 1999 annual review and price change.

7	Profit Sharing	There will be 50/50 sharing if the Company's earnings fall/increase 350 or more basis points below above the target return on common equity, as measured by its ROE for regulatory accounting purposes.
8	Annual Review Proceeding	BHE shall file specified information on March 15, 1998 and February 15, 1999. The information will be used to compute the annual prices changes, which will go into effect on May 1, 1998 and May 1, 1999.
9	Customer Service Standards	The Commission will continue to monitor the Company's customer service and reliability but will not implement a formal customer service standard at this time.